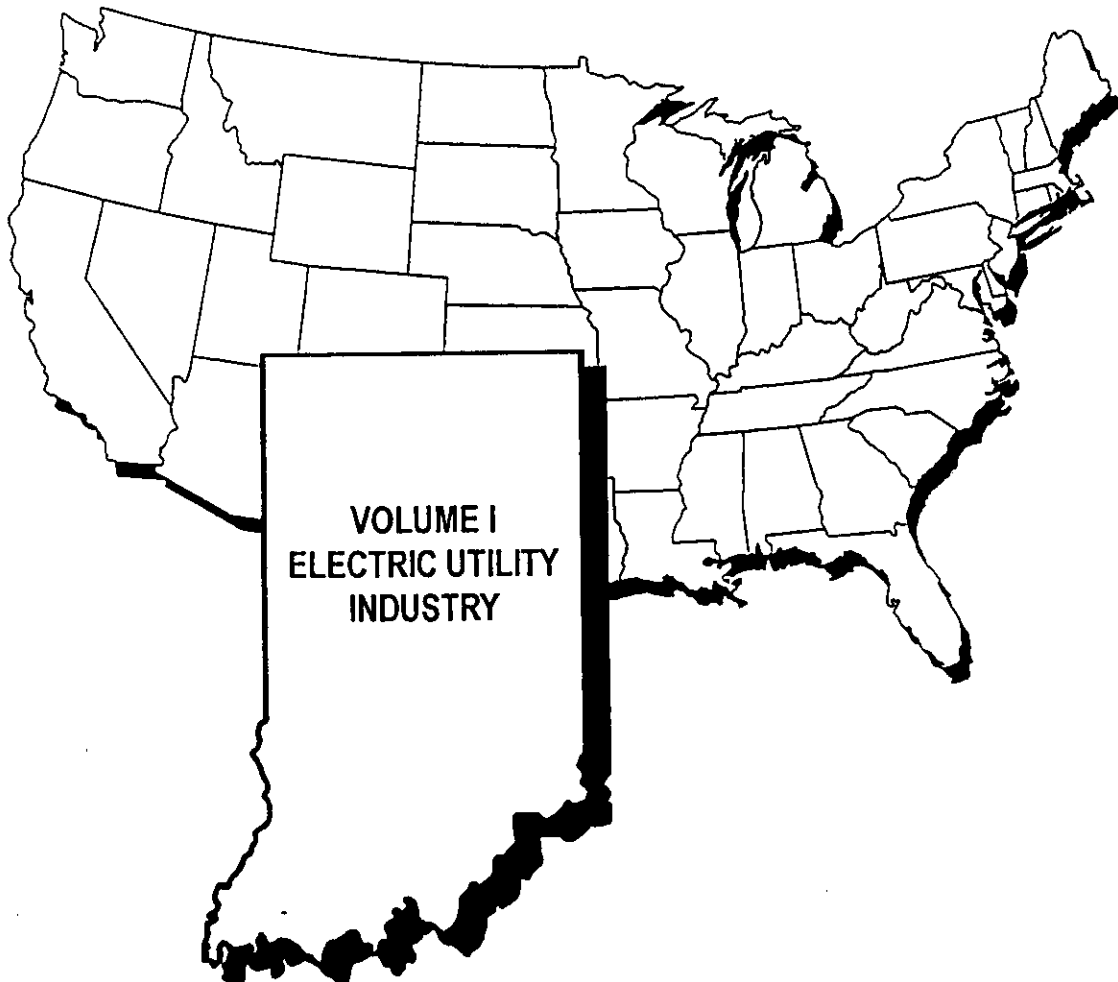


**ENERGY REPORT
TO THE
REGULATORY FLEXIBILITY COMMITTEE
OF THE
INDIANA GENERAL ASSEMBLY**

by the
INDIANA UTILITY REGULATORY COMMISSION



October 1, 1996
(Revised November 1996)

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I. SCOPE OF THE ENERGY REPORTS

This is the first annual Energy Report (Electricity and Gas) to be filed by the Indiana Utility Regulatory Commission with the Regulatory Flexibility Committee of the Indiana General Assembly under IC 8-1-2.5-9. With the approval of the Committee's Chairmen, this Report is submitted on October 1, 1996. The Act specifies:

The commission shall, before July 1, 1996, and before July 1 of each year after 1996, prepare for presentation to the regulatory flexibility committee an analysis of the effects of competition or changes in the energy utility industry on service and on the pricing of all energy utility services under the jurisdiction of the commission.

To be responsive to the Regulatory Flexibility Committee's charge to address specific issues, the Energy Report will provide information concerning:

- 1) The effects of competition or changes in the energy utility industry and the impact of competition or changes on residential rates.
- 2) The status of modernization of the energy utility facilities in Indiana and the incentives required to further enhance this infrastructure.
- 3) The effects on economic development of this modernization.
- 4) The traditional method of regulating energy utilities and this method's effectiveness.
- 5) The economic and social effectiveness of traditional energy utility service pricing.
- 6) Other energy utility issues the committee may consider appropriate.

Despite important similarities between gas and electric utilities and the fact that they compete against each other, there are important distinctions between electric and gas utility industries that warrant separate discussions. Because of the important distinctions between the two industries, the Energy Report is divided into separate volumes to deal with the electric and gas utility industries. The Electric and Gas Volumes are intended to provide the General Assembly with an unbiased and reasonably comprehensive discussion of emerging competition in the electric and gas industries.

While we anticipate the General Assembly will be primarily interested in competition issues, it is important to describe the changing structures of these industries. The changing structure of these two industries, which have a long tradition of monopoly and regulation, has largely been the result of changes in federal law and federal regulatory policy designed to promote competition. For this reason, the Energy Report discusses the basic structures of the gas and electric industries in the context of utility regulation.

II. EXECUTIVE SUMMARY

Introduction

With its passage of the Energy Policy Act of 1992, Congress opened the door to wholesale competition in the electric utility industry by expanding the authority of the Federal Energy Regulatory Commission, or FERC, to approve power producers' applications for transmission services. FERC's subsequent rules, adopted in April 1996, are designed to increase wholesale competition in the industry through the nation's transmission system, remedy undue discrimination in transmission, and establish standards for stranded cost recovery.

The federal act included a dispute resolution process for power producers that were not granted open, comparable and nondiscriminatory access to the transmission lines owned by utilities, which also generate, transport and sell power. The FERC attempted to address these disputes on a case-by-case basis, and in a number of ways, but ultimately settled the issue this year in its Order 888 in a generic ruling. State utility commissions are currently assessing the order's implications for their own local utilities.

The acceleration of wholesale competition as a result of FERC Order 888 prompted some power producers, large customers and low-cost electric utilities to call for competition at the retail level as well. Bills that would allow retail competition have also been introduced in Congress. Some state regulatory commissions and/or state legislatures have taken action toward offering customers choice, some are studying the issues, and others have taken little or no action.

Electric utilities across the nation are openly anticipating a change in traditional regulation that would allow retail competition in some form. This anticipation has caused two visible reactions in the industry: internal restructuring, which included cost cutting by the utilities, which under traditional cost-based regulation have little incentive to reduce costs; and mergers and acquisitions, which have allowed some energy utilities to join forces with others to enhance their market position in the future environment. In 1995, seven mergers among energy utilities were announced in the US, representing \$28 billion in market value. None of these were in Indiana.

Senate Enrolled Act 637, 1995, codified as I C 8-1-2.5, allows energy utilities the flexibility to adapt to market changes. The act allows the IURC, when requested by a utility, to move from historic rate-based regulation to alternative regulation, if that is in the public interest.

Background

The electric industry is the largest industry in the US, with nearly 3,500 companies providing service across the country. Of that total, the largest 200 utilities provide service to nearly 80 percent of the nation's retail customers.

The transmission systems of these utilities are interconnected throughout the US. A power failure at one utility on the East Coast in 1967, which triggered a multi-state failure, prompted the formation of the North American Electric Reliability Council and the establishment of nine regional reliability councils. These councils are designed to ensure that should failures along the transmission system occur, the interconnected utilities would be protected. Indiana belongs to the East Central Area Reliability Coordination Council, or ECAR, which also includes Michigan, Ohio, Kentucky, West Virginia, Pennsylvania, Maryland and Virginia.

There are three primary functions within the electric industry:

- Generation -- the production of power performed by utilities, independent power producers, and co-generators.
- Transmission -- the transportation of electricity through high-voltage transmission lines owned and operated by electric utilities.
- Distribution -- the transportation of power at lower-voltage to consumers.

The FERC's Orders 888 and 889 provide for a competitive wholesale market. With regard to transmission, jurisdictional issues are already hotly contested between the states and the FERC. The distribution function is widely expected to remain the jurisdiction of the states due to the utilities' natural monopoly over those services.

The FERC has regulatory oversight of wholesale transactions, which include both transmission and generation cost components. The IURC has regulatory oversight of most intra-state, retail operations of the electric utilities under its jurisdiction.

The IURC's Role

More than 2.5 million Indiana customers receive electric service from Indiana's 127 electric utilities. The IURC regulates 80 of these utilities, which together generated more than

\$4 billion in revenue last year. Of the total, there are six investor-owned utilities, 43 rural electric membership cooperatives and 78 municipals. Five of the REMCs have withdrawn from the IURC's jurisdiction under the provisions of Senate Enrolled Act 575, approved by the General Assembly and enacted as IC 8-1-17-22.5 in 1995. Forty-two of the municipals have withdrawn under IC 8-1.5 -3-8, which allows the local governmental body to self-regulate its municipal utilities.

The five largest investor-owned electric utilities, which provide electric service to about 90 percent of the state, are Northern Indiana Public Service Company (NIPSCO), Indianapolis Power & Light Company (IPL), Southern Indiana Gas & Electric (SIGECO), AEP Indiana, aka Indiana Michigan Power (I&M) and PSI Energy (PSI).

Each of these IOUs has a favorable business position; their electric operations, as well as their finances, are solid; and their managements are considered to be proactive. As a whole, these utilities generally are low-cost providers of electricity as compared to the national average.

Each of the IOUs has taken steps to cut costs and restructure their business operations as they adapt to the evolving regulatory environment. PSI Energy was one of the nation's first utilities to join the merger trend in 1994 when it merged with Cincinnati Gas & Electric to form Cinergy. Cinergy, the utilities' parent company, is the 13th largest gas and electric utility holding company in the US.

The IOUs are participating in the formation of the Midwest Independent System Operator (ISO), which is an association of transmission-owning utilities, whose purpose is to meet the open, comparable and nondiscriminatory access requirements of FERC Order 888.

Hoosier Energy, Wabash Valley Power Association (WVPA) and the Indiana Municipal Power Agency (IMPA) are also participating in the formation of the ISO. Hoosier and Wabash Valley generate, purchase and sell electricity to member REMCs at wholesale rates. IMPA generates and purchases electricity and sells it at wholesale rates to member municipal electric utilities.

Twenty-two utilities from seven Midwestern states are participating in the formation of the ISO. Operation of the ISO is contingent upon FERC approval, which is to be sought in 1997. Operation is expected to begin the following year. The ISO would be a non-profit organization, independent of transmission owners. Essentially, the utilities would turn over the planning and administration of their transmission systems to the ISO.

Approximately 30 percent of the electric utilities' costs are directly attributable to the cost of purchasing fuel used to generate electricity and/or purchasing wholesale power. The utilities file quarterly requests for fuel cost adjustments to their rates to reflect and recover the changing costs of power and fuel, which in Indiana generally is high-sulfur coal. Utilities also use oil and gas-fired turbine engines to generate electricity for peak demand.

The IURC monitors whether the utilities are buying and generating at the least possible costs through the fuel adjustment clause, or FAC. The FAC procedure allows electric utilities to pass on to customers changes in the wholesale cost of power and the market price of fuel used to produce power. It also reduces the frequency with which the utilities file base rate cases with the IURC to increase their rates and charges due to the increased costs of generation and purchased power. This aspect of the FAC benefits customers by reducing the frequency of rate cases and the associated rate case expenses, which are costs the utility can recover in rates.

The FAC also allows the IURC to regularly monitor whether the utilities are earning in excess of the rate of return assigned to them in their last base rate case. If the utilities are over-earning, they are required to refund that over-earning to customers through reduced rates. The General Assembly in 1995, under I C 8-1-2-42, changed the FAC process and extended the period for the earnings calculation to five years or the period since the last rate case, whichever is longer.

When establishing base rates for the utilities through a traditional rate case, the IURC not only takes into account the cost of producing and delivering electricity to customers, but also allows a reasonable rate of return on investment for the IOUs, a reasonable rate of return on net plant for municipally owned utilities, and a margin for future investment for the REMCs.

The desire by various groups in the electric marketplace for retail competition was the impetus for state commissions to begin actively considering changing the regulatory system. At the urging of utilities, consumers and large industrial customers, the IURC in December 1994 began hosting Electricity Forums among the state's electric utilities, consumer groups and other interested parties. Through the forums, these parties have provided the IURC with insight regarding how best, if at all, to alter electric utility regulation.

Included in the forum discussion has been the issue of stranded investment that could occur. If retail competition is allowed, customers of higher-cost utilities will likely leave those utilities to find cheaper sources of power. Large industrial customers frequently provide a large part of many utilities' revenues, and their high demand for power has caused the utilities to

design their generation resources to meet those customers' needs. If the large customers leave, the utilities must draw upon their remaining customers to recover their stranded investment in generation resources.

Under the current system of regulation, in most cases, the utilities were given state regulatory approval to recover those investments from ratepayers. Financial analysts have estimated that nationwide, between \$20 billion and \$200 billion in stranded investments could occur if retail competition were allowed.

Indiana electric utilities are relatively low-cost power providers and, in a competitive retail market, would likely attract new customers who currently must buy power from high-cost power providers. High-cost providers are generally utilities that have invested in expensive nuclear or other types of power plants, and as a result have higher rates than utilities without those embedded costs. Because transportation of the power would carry a separate charge, however, some customers may find "cheaper" power from alternative suppliers is too expensive to actually buy.

Some utilities and consumer advocates, however, are concerned that despite the theory that stranded investment will not have a detrimental effect in Indiana, small customers could suffer if their interests are not adequately addressed.

Through the use of Economic Development Rates, or EDRs, and the allowance of negotiated contracts between utilities and large industrial customers, the IURC has allowed some customers to pay customer specific rates. While states and utilities do compete for new businesses, the EDRs and negotiated contracts do not constitute retail competition because customers have no choice in service provider once they locate their business, and the rates are cost-based. Further, the customer specific rates are for limited contract terms.

Developments Toward Alternative Regulation in Indiana

INDIANA STATEWIDE ARP

The IURC is considering a case filed by a group of rural electric membership cooperatives, or REMCs, which are seeking alternative regulation under the provisions of Senate Enrolled Act 637, 1995, IC 8-1-2.5. The petition, filed June 10, 1996, on behalf of most of the state's REMCs, seeks authority for streamlined rate regulation, under which rate changes involving no more than 3 percent of additional annual revenue could be implemented without a hearing before the IURC in the absence of a complaint.

Under the proposal, the REMCs would also be allowed to reduce rates without a hearing. The REMCs would provide the IURC with informational tariffs when rates are changed, but would not be required to have the IURC's approval prior to adjusting the rates. The REMC's plan would allow an opportunity for the REMCs' members, or the Office of the Utility Consumer Counselor, to seek a hearing on the rate changes.

Under the proposal, the rate adjustments would be presumed reasonable and the complainant would have the burden of proof in proving otherwise. The petition also advises the IURC that if REMCs are given this flexibility, they will not opt out of the IURC's jurisdiction. A procedural schedule to adjudicate the petition has not yet been established.

PSI'S RIDERS 18 AND 19

The IURC on September 27, 1996, disallowed a proposal from PSI to modify two of its tariffs, which would have offered modified competition to its customers. PSI had asked to modify the tariffs as part of its request to increase base rates. The IURC declined to take such a drastic step toward this type of regulatory change without a mandate from the General Assembly, a recommendation from the IURC Electricity Forums or a federal directive. The IURC was also concerned about the effect the tariff modifications, and retail competition in general, would have on residential ratepayers.

Conclusion

This is a challenging time for state lawmakers, regulators and utilities as they consider the best manner in which to proceed as they contemplate changes in the electric marketplace. In subsequent energy reports, the IURC will continue to apprise the General Assembly of the status of changes in the electric industry.

III. AN OVERVIEW OF THE PUBLIC POLICY DEBATE

A number of states are examining the desirability of introducing retail competition in the electric utility industry. Retail competition would allow retail customers (i.e., residential, commercial and industrial) to purchase their electricity from suppliers other than the local utility while continuing to purchase transmission, distribution and other necessary services (e.g., metering and billing) from the local utility.

Numerous factors have stimulated interest in retail competition for electricity. First, competition has been edging into portions of the electric utility industry, especially the bulk power (or wholesale) market, for a long period of time. Second, recent experiences with increased competition in the telephone and natural gas industries have been positive. Third, large price differences exist between utilities across the nation and within most states. Fourth, traditional regulation sets electricity prices based on embedded costs and for many utility companies these costs are high compared to the cost of power from new generation facilities. Finally, the perception of increased international economic competition and competition among the states for economic development has highlighted the importance of competitive electricity prices.

Unbundling Retail Services

Traditionally, retail electric energy service has been provided on a bundled basis. This means that for one price retail customers have received a service that really consisted of a package of individual services. These individual services include generation, transmission, distribution, the provision of ancillary services, meter reading and billing services, among others.

The most direct method of promoting competition is to require that monopoly services, like transmission and distribution, be unbundled from other services, like generation and the provision of some ancillary services, which are potentially competitive. Unbundling involves offering each of the different components of retail electric service at separate and distinct prices. Monopoly services would continue to be provided on a regulated basis.

Unbundling electric service can improve economic efficiency in a number of ways:

1. Unbundling can foster competition for the provision of certain functions currently provided on a monopoly basis by electric utility companies.

2. Unbundling can benefit customers by allowing them the opportunity to choose from a wider range of services.
3. Unbundling can make the pricing of the individual components of electric service more transparent by better reflecting the economic cost of providing specific services.

Unbundling retail electric service, however, would require that state legislators and regulators tackle a host of public policy issues.

Legislative and Regulatory Policy Questions

The key question to be answered is how best to make the transition from regulated monopoly to an industry structure with a competitive generation market while maintaining a high degree of system reliability? To deliver power to final customers, generating companies must have access to the transmission and distribution facilities that are owned and operated by the local utility. These transmission and distribution facilities are likely to remain natural monopolies for the foreseeable future. The concern is that the utility which controls the essential transmission and distribution facilities has an incentive to favor its own generation facilities while denying access or providing inferior access to these key facilities for competitors. Thus, the debate is not "regulation" versus "deregulation and competition," but how to combine competition, where it can be effective, with redesigned regulation, where effective competition is unlikely to develop.

Policy makers must also recognize the unique nature of electricity (non-storable, must be consumed when produced, follows the path of least resistance, can be transmitted over long distances) and the interconnected network make proper planning and minute-by-minute coordination an absolute necessity. Such planning and coordination are currently the explicit charge of the control area utilities under the oversight of state commissions. Extensive changes to the industry structure means that thorough consideration must be given to the reallocation and reassignment of the vital functions performed by the control area utilities.

Another question for decision makers is how to protect customers during the transition? Experience with natural gas and telecommunications indicates that competitive options frequently develop for some types of customers sooner than for other types of customers. For example, public interest will not be served if proposals for direct access by retail customers unreasonably shift system costs from large industrial customers to residential and commercial

customers. The risk is that shared system costs will be borne by residential and commercial customers who will not have the access to competitive alternatives that industrial customers will.

The degree of unbundling and competition, whether wholesale or retail, is a legislative policy choice. States are debating the choices: implement a customer choice program, wait to implement customer choice until after wholesale competition has developed further, or perhaps wait and learn from the mistakes of other states.

The outcome of these increased competitive pressures is uncertain, but they are causing regulators and utilities to analyze a wide range of policy questions that must be answered relating to the formation and development of retail competition in the electric utility industry. Some of these questions include:¹

1. What would be the meaning of "obligation to serve" in a retail choice environment?
2. How would the structure of the industry change?
3. What services would continue to be regulated? How should they be regulated?
4. How could competition and regulation coexist?
5. How could core customers be protected?
6. What would be the responsibility of departing customers for the local utility's stranded costs?
7. When and under what conditions should retail choice be allowed?
8. How would pricing for different electricity services change?
9. How would services be unbundled and priced in a retail choice environment?

These and other questions have been discussed and debated in a series of forums sponsored by the IURC. Informally known as the Electric Competition Forum, twelve meetings have been held from December 1994 through July 1996. The next scheduled meeting is November 1, 1996. The Commission's goal in these meetings is to discuss the implications of competition and its effect on the state and ratepayers, and to consider what, if any, changes to recommend to the General Assembly.

¹ National Regulatory Research Institute, Overview of Policy Issues Relating to the Retail Wheeling of Electricity, May 1994, p. 86.

IV. THE INDIANA ELECTRIC UTILITY INDUSTRY

A. Structure of the Electricity Industry

Electric utilities in the United States are categorized by their type of ownership--government (federal and municipal), cooperative and investor-owned. The utilities have the same goal, to provide reliable electric service at reasonable cost to their customers, but distinct corporate structures result in different methods employed by the utilities to meet this goal. Because of the differences in utility structure, government policy does not affect each type of utility in the same manner.

1. Investor-Owned Utilities

The type of utility that is most significant in terms of generation and customers served is the investor-owned, or IOU. Five major investor-owned utilities operate within the state--Indianapolis Power & Light (IPL), Indiana Michigan Power (I&M), Northern Indiana Public Service (NIPSCO), PSI Energy (PSI) and Southern Indiana Gas & Electric (SIGECO). IOUs are for-profit enterprises funded by debt and equity. IOUs are judged by the same standards as any publicly held company; investor services rate their bond issues and make recommendations on stock purchases. Most IOUs are vertically integrated, meaning they own facilities for generation, transmission and distribution. The significant level of investment needed to construct and maintain the systems results in high leverage for many IOUs.

All of Indiana's IOUs are owned by holding companies. Holding companies are entities that own enough stock in another company to influence management of the held company. Holding companies are popular in the electricity industry because its capital-intensive nature makes it economical to combine functions. Two of the state's IOUs, PSI Energy and Indiana Michigan Power, are subsidiaries of multi-state holding companies (Cinergy and American Electric Power, respectively). Multi-state holding companies are required under the Public Utility Holding Company Act (PUHCA) to register with the Securities and Exchange Commission (SEC), and the SEC monitors their actions to ensure compliance with PUHCA regulations.

Table IV.1 presents generation and sales information for Indiana's 5 major IOUs. The "Sales for Resale" illustrates that IOUs are typically able to generate enough power for their own requirements and produce power for sale in the wholesale market.

TABLE IV.1: INVESTOR-OWNED UTILITY STATISTICS – 1994

UTILITY	CAPACITY (MW)	TOTAL SALES (GWh)	SALES FOR RESALE (GWh)	RESIDENTIAL SALES (GWh)	COMMERCIAL SALES (GWh)	INDUSTRIAL SALES (GWh)
I&M	4,448	26,767	11,147	4,937	4,149	6,453
IPL	2,986	13,136	482	4,077	2,195	6,306
PSI	5,781	28,369	6,941	6,575	5,571	9,221
NIPSCO	3,392	15,536	564	2,552	2,737	9,542
SIGECO	1,238	5,566	1,235	1,246	1,137	1,928

Source: 1994 Annual Reports and FERC Form 1

2. Municipal Utilities

There are 78 municipally owned electric utilities in Indiana, 36 of which are regulated by the IURC. Municipals are organized as nonprofit local government agencies and pay no taxes or dividends, although net revenue can be turned over to the general city fund if the city elects to do so. Municipals raise capital through the issuance of tax-free bonds.

Municipal utilities typically own very little, if any, generating capacity; they purchase electricity from other sources and resell it to their retail customers. The reseller status limits a municipal's need to raise large amounts of capital because it does not invest in capital-intensive generation. The advantages of a "muni" include the local government receiving revenue from earnings, and generally lower electricity rates for the municipality due to the low capital investment and tax-exempt status.

Many municipals in the state are members of the Indiana Municipal Power Agency (IMPA). IMPA was created by a group of municipalities in 1980 to jointly finance and operate generation and transmission facilities and purchase power. IMPA is a political subdivision of the state under Indiana Code 8-1-2.2 and is not subject to state or federal income taxes.

IMPA owns generating facilities and has member-dedicated generation. It also holds ownership interest in two units, Gibson 5 (co-owned with PSI and Wabash Valley Power Association) and Trimble County 1 (co-owned with Louisville Gas and Electric and the Illinois Municipal Electric Agency). It meets the rest of its members' needs through purchased power.

3. Cooperatives

Another type of non-profit electric utility is the cooperative. Forty-three distribution co-ops exist in Indiana. Co-ops were originally formed to bring electric service to rural areas. They are similar to municipals in that they generally purchase electricity from private suppliers at wholesale rates rather than owning generation facilities.

Although co-ops were created to distribute power, since the 1960s over 50 generating and transmission (G & T) cooperatives have been formed nationally to supply power to distribution co-ops. Within Indiana, there are two G & T co-ops: Hoosier Energy and Wabash Valley Power Association. These G & T co-ops serve as coordinators of bulk power supplies and transmission services for its members, as IMPA does for municipals.

Table IV.2 illustrates the proportion of power purchases to generation for IMPA and the generation and transmission cooperatives, Hoosier Energy and Wabash Valley Power Association. It is seen in the table that Hoosier Energy owns a significant amount of generating capacity compared to Wabash Valley.

TABLE IV.2: IMPA/G&T CO-OPS STATISTICS -- 1994

UTILITY	CAPACITY (MW)	GENERATION (GWh)	PURCHASES (GWh)	SALES (GWh)
IMPA	554	1,412	2,604	3,887
Hoosier Energy	1,266	6,386	112	6,311
Wabash Valley	156	936	3,051	3,748

Source: 1994 Annual Reports to the IURC

B. Regulation of Electric Utilities

1. State Regulation

The Indiana Utility Regulatory Commission receives its authority from Indiana Code Title Eight. The Indiana Administrative Code and other statutes further define the role the Commission takes in regulating the state's utilities.

The goal of the Commission is to assure that utilities and others use adequate planning and resources for the provision of safe and reliable utility services at reasonable cost. The

Commission is not an advocate of the public or the utilities. It is a fact-finding body required by law to make decisions that balance the interests of all parties concerned.

In proceedings before the IURC, Indiana's ratepayers are represented by the Office of the Utility Consumer Counselor (OUCC). The OUCC is a separate state agency unaffiliated with the IURC that serves as an advocate for the state's utility customers. Other parties with interest in a specific case may participate in proceedings as an intervenor.

The IURC sets retail rates for IOUs, co-ops and municipals, and wholesale rates for Hoosier and Wabash Valley. However, municipal and cooperative utilities may remove themselves from Commission jurisdiction through an ordinance of the local government or a referendum ballot by the voters of the municipality or co-op. Municipalities are granted this right under Indiana Code 8-1.5-3-9 and co-ops under 8-1-13-18.5. Thus far, forty-two municipals and five cooperatives have withdrawn from the IURC's jurisdiction.

The Commission also must approve long-term financing for municipals and IOUs. It must approve bond sales for IMPA if the proceeds are to be used for a construction project. Co-ops are not required to obtain approval for financing, although the Commission indirectly reviews it via rate cases.

Indiana Code 8-1-8.5 requires the state's utilities to receive Commission approval before they construct any generating facilities. To supplement the Certificate of Need law and respond to utility concerns regarding the Commission's expectations for long-term planning, in 1995 the IURC adopted Integrated Resource Planning and Demand-Side Management rules (IAC 8.4-7 and 8.4-8). Integrated resource planning involves a utility considering a range of supply-side and demand-side options to develop a least-cost plan to meet future demand. The state's IOUs, G & T co-ops and IMPA are required to submit IRPs so the Commission may prepare an analysis of the state's long-term electricity needs. The first plans were submitted in November 1995.

2. Flexible Regulation

In 1995 the Indiana General Assembly passed Senate Enrolled Act 637, legislation designed to allow more flexible regulation of energy utilities. The Act, codified as IC 8-1-2.5, requires the Commission to consider any petition filed by a utility proposing alternative regulation. The Commission must determine whether the proposal would be beneficial to the utility, its customers and the state, and if it will promote efficiency and competition.

Indiana Statewide Association of Rural Electric Cooperatives filed a petition on behalf of 32 REMCs with the IURC on June 10, 1996, seeking approval of an alternative regulatory plan (ARP). The proposed ARP is the first, and thus far the only, filing by an electric utility under IC 8-1-2.5.

Indiana Statewide is petitioning the IURC to decline to exercise its jurisdiction over the petitioning REMCs on most issues, although the co-ops would not formally opt out of IURC jurisdiction.

1. The ARP would give deference to the REMC's management with respect to personnel, operating and management practices affecting rates and charges.
2. The REMC's rates shall be independent of the rates of its wholesale supplier, whether that supplier be a G & T REMC or any other power supplier.
3. Reductions in revenues applied to all rate classes utilizing an existing rate design based on a cost of service study performed consistent with generally accepted practices and filed with the IURC shall be presumed to be reasonable, and may be placed in effect upon thirty days notice to members.
4. Reductions involving new rate design based on cost of service established by a current cost of service study filed with the IURC may be implemented thirty days after notice of the proposed rate changes to customers and shall become permanent within sixty days of such notice unless a petition for a hearing is requested within thirty days of notice by the OUCC or one percent of the REMC's members. The rates proposed by the REMC shall be presumed reasonable and the person(s) filing the request for hearing shall have the burden of proving otherwise.
5. Increases in recurring rates shall be conclusively presumed reasonable and may be placed into effect upon thirty days notice to members if the new rates do not produce additional annual revenues of more than 3% and the rate design is consistent with a cost of service study on file with the IURC.
6. Other rate increases would be placed into effect upon thirty days notice to members and shall become permanent sixty days thereafter unless a request for hearing is received from the OUCC or one percent of the REMC's members

within twenty days. The proposed rates once placed into effect shall not be subject to refund.

7. It also provides for customer specific contracts for new load or to retain existing load in excess of one megawatt, at the sole discretion of the REMC's board and without the necessity of IURC approval. The ARP would also require the IURC to keep on file the contract, but it would be on a confidential basis.

Senate Enrolled Act 637, 1995, codified as IC 8-1-2-42, also changes how the Commission calculates excess earnings in fuel cost adjustment proceedings. Utilities are required to refund to customers any excess revenue earned through quarterly fuel cost adjustments (adjustments that permit utilities to pass along to customers an increase in fuel cost). Previously, the calculation was based on a one-year average earnings test. The new law extends the period used for earnings calculation to five years or the period since the last rate case, whichever is longer. Indiana Michigan Power became the first utility to exercise the new law, and did not have to return \$1.4 million in earnings that previously would have been refunded to ratepayers because the company did not have excess earnings over a five year period.

3. Federal Regulation

Utilities must comply with federal directives as well as state. The Federal Energy Regulatory Commission (FERC) is one of two federal agencies that monitor the financial and economic activities of utilities. The FERC has authority over the following areas:

1. Regulation of wholesale rates and transactions
2. Regulation of rates charged by federal power marketing associations
3. Issuance of wheeling orders
4. Administration of Public Utilities Regulatory Policies Act (PURPA) provisions related to small power producers and cogenerators
5. Approval of proposed utility mergers.

The Securities and Exchange Commission (SEC) regulates non-exempt (registered) holding companies, which typically are those that operate interstate. Under the Public Utility Holding Company Act (PUHCA), registered holding companies must fulfill extensive reporting and accounting requirements for the SEC. The SEC must approve any holding company activity involving the following transactions:

1. Issuance or sale of securities
2. Acquisition of any securities or utility assets or any interest in a non-utility business
3. Sale of utility assets or securities
4. Provision of intrasystem loans or extensions of credit.

4. Clean Air Act Amendments

Federal environmental legislation also has a significant impact on the Indiana electricity industry. Most recently, the 1990 Clean Air Act Amendments (CAAA) placed limits on emissions from utility generation facilities. The Act required reduction of sulfur dioxide and nitrogen oxide emissions, and imposed a nationwide cap on emissions of these pollutants. SO₂ and NO_x are produced by burning fossil fuels.

The Clean Air Act Amendments established two phases to reduce emissions. Phase I requirements, which affected the 110 "dirtiest" power plants, limited SO₂ emissions to 2.5 pounds per million Btu (MMBtu) of fuel burned. This standard went into effect on January 1, 1995. Phase II begins in 2000, and limits all plants to emissions of 1.2 pounds of SO₂ per MMBtu. Phase II also places a cap on SO₂ emissions of 8.9 million tons per year, regardless of the number of generating facilities online.²

Table IV.3 illustrates the effect of Phase I and II compliance on Indiana utilities. Almost half of the state's generating capacity is affected by Phase I, and almost 60% by Phase II.

TABLE IV.3: INDIANA CAAA COMPLIANCE

PHASE	NUMBER OF AFFECTED UNITS	AFFECTED CAPACITY MW	AFFECTED CAPACITY % OF TOTAL
I	37	11,190	48.7
II	67	13,534	58.9

Source: National Regulatory Research Institute

To promote the most efficient method of attainment, the CAAA created a system of marketable pollution credits. Utilities with plants emitting less than their limit earn allowances that can be sold or traded to utilities that emit more than the standard. The allowances create an

² Charles F. Phillips, Jr., The Regulation of Public Utilities, Public Utilities Reports, Arlington, VA, 1993, p. 594.

incentive for those companies that can reduce their emissions cheaply to over comply and sell allowances to utilities with compliance costs that are higher than the cost of an allowance.

In response to the Clean Air Act Amendments, in 1991 the Indiana General Assembly passed Senate Enrolled Act 514 (Indiana Code 8-1-27). The legislation permits a utility to submit to the Commission its Clean Air compliance plan before implementation. Prior approval of the plan provides some measure of protection to utilities from after-the-fact disallowance of compliance costs, and gives interested parties the opportunity to review and comment on the plan. Utilities with approved plans are also allowed to include the pollution control equipment as construction work in progress (CWIP) in the rate base.

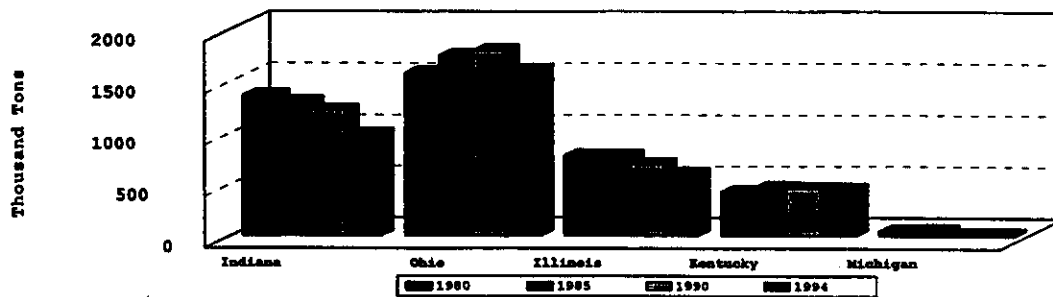
Three utilities presented compliance plans to the Commission: SIGECO, IPL and PSI.³ SIGECO elected to install a flue gas desulfurization unit ("scrubber") and low nitrous oxide burners at its Culley plant. IPL chose the same options for its Petersburg station, and will install low nitrous oxide burners at its Stout and Pritchard units in Phase II and continue to use low sulfur coal at those facilities. PSI planned a combination of scrubbing, low NO_x burners, flue gas conditioning and switching to lower sulfur coal for Phase I and II compliance.

These compliance plans helped contribute to sizable decreases in Indiana's SO₂ and NO_x emissions before the Phase I deadline. By 1994, the state has reduced its SO₂ emissions 27.4% from 1980 levels, and NO_x emissions 16% from 1985.⁴ Figure IV.1 illustrates the reductions in SO₂ emissions in the East North Central region between 1980 and 1994.

³ SIGECO, Cause No. 39347, October 14, 1992; IPL, Cause No. 39437, August 18, 1993; PSI, Cause No. 39346, October 27, 1993.

⁴ Environmental Protection Agency, Acid Rain Program Emissions Scorecard 1994, December 1995, pp. 6-7.

Figure IV.1: Sulfur Dioxide Emissions



5. Nuclear Waste

Indiana electric utilities were not immune to the construction problems of the 1970s. PSI Energy and its minority partner Wabash Valley Power Association Inc., faced huge escalations in the costs of construction of the Marble Hill nuclear plant. The plant was ultimately abandoned in 1984, leaving both organizations in financial chaos. Northern Indiana Public Service Company abandoned the construction of Bailey nuclear generating station, although it suffered fewer financial consequences than PSI and Wabash.

The Nuclear Waste Policy Act of 1982 established a framework for the nation's high-level radioactive waste program. The law included provisions for the Department of Energy (DOE) to locate, build and operate a deep, geological repository for spent nuclear fuel.

In 1987, Congress amended the law and designated Yucca Mountain, Nevada as the only potential repository site for further scientific study. The DOE was authorized, but not required, to develop an above-ground monitored retrievable (interim) storage facility.

Since 1983, the federal government has charged the nation's electricity consumers one-tenth of a cent for every kilowatt hour (kWh) of nuclear-generated electricity consumed. This amounts to more than \$11 billion for the Nuclear Waste Fund but only about \$4 billion has actually been spent on civilian high-level nuclear waste.

The program has been beset by numerous delays and cost overruns. The opening date for the permanent repository has been pushed back to the year 2010, and even though the DOE still has a responsibility to begin accepting spent fuel in 1998, an interim facility is not currently being developed.

While there are no nuclear power plants in the state of Indiana, Indiana Michigan Power Company (I&M), headquartered in Ft. Wayne, operates the Cook nuclear plant on Lake Michigan near Bridgman, Michigan. The Cook unit has a total generating capacity of 2,110 megawatts, 47% of I&M's total capacity and 11% of the state's total generating capacity.

I&M provides power to 444,000 Indiana customers. These customers are contributing to the Nuclear Waste Fund in two ways. First, I&M collects \$3 million a year for the amount of fuel consumed at the Cook plant prior to April 7, 1983. This represents the electricity generated prior to the enactment of the Nuclear Waste Policy Act of 1982.

Second, I&M must pay to the Department of Energy one-tenth of a cent for every kilowatt hour generated and sold from the Cook plant. Indiana's share of this has averaged \$8.514 million over the past two years.

Therefore, Indiana ratepayers have paid, and will continue to pay, the federal government \$11.514 million per year. This amounts to over \$12 per year for each residential customer; substantially more for commercial and industrial customers.

As of June 30, 1995, Indiana's total liability to the Nuclear Waste Fund exceeds \$280 million.

Investments. Higher retail kilowatt hour sales, PSI's electric rate increases which became effective in February and March 1995, and a full year's effect of CG&E's electric rate increase which became effective in May 1994 contributed to the \$165 million increase in Cinergy's electric operating revenues for 1995. Electric fuel costs, Cinergy's largest operating expense, remained relatively constant in 1995, showing less than a 1% increase over 1994. Other operating costs decreased by 5.2% generally due to savings from the merger. Net income for 1995 was \$347 million for Cinergy.

Over the five years ended 1994, PSI's annual retail kWh sales growth has averaged 4.1%. Firm wholesale sales represent around 9% of PSI's total kWh sales and 7% of electric revenues. These sales are made to WVPA, IMPA and other smaller municipalities and rural electric cooperatives under long-term contracts.

5. Southern Indiana Gas & Electric

Electric revenues increased 5.6% over 1994 due to implementation of the second and third steps of a three step increase in retail electric rates and increased sales to retail and wholesale customers. Although electric generation was 3.8% greater, a result of increased sales, fuel for electric generation, the most significant electric operating cost, declined 2.6% due to lower coal costs. Other operating costs rose 3.7% primarily due to additional post-retirement benefits other than pensions. Net income for 1995 was \$44.8 million as compared to \$39.9 million in 1994.

B. Municipals

During 1995 IMPA was successful in increasing equity while decreasing rates. The average cost per kilowatt hour to members decreased 5.6%. The emerging competitive wholesale market enabled IMPA to better utilize its resources in 1995 and lower its costs. In addition, IMPA settled a wholesale rate case with Cinergy that helped reduce costs.

Equity increased by \$7.4 million to \$50 million. Net income was 24% lower than 1994 resulting from the IMPA Board's voluntary reduction in debt service coverage. Other financial and operating results in 1995 included the following:

- * IMPA's sales to members decreased 1% for the year. This decrease was the net result of the 5.6% decrease in the average cost per kilowatt hour to members offset by a 4.6% increase in energy sales.

- * Operating expenses increased in 1995, reflecting the higher energy sales. In addition, maintenance expense increased in 1995, as both Trimble County and Gibson 5 underwent substantial planned maintenance. The planned outages resulted in both higher maintenance and purchased power expenses. Fuel expense decreased 2.6% in 1995 as LG&E lowered fuel cost per kilowatt hour by 11% at the Trimble County plant.

For 1996, IMPA's management expects rates to members to decrease from the 1995 levels and projects an income of \$4.0 million.

C. Cooperatives⁶

As discussed earlier in Part IV, Hoosier Energy and Wabash Valley Power Association are the two generation and transmission cooperatives in Indiana. In the past the Rural Utilities Service (RUS, formerly REA) was the main source of funding for cooperative utilities. RUS is still a major source of funding for co-ops, but many use other financial institutions as well.

1. Hoosier Energy

During 1995 Hoosier Energy experienced a 6.5% increase in sales to its member distribution systems. This increase was primarily due to an 8% general rate decrease implemented in 1994 and a 5% fuel-related reduction in 1995. In addition to decreases in fuel costs Hoosier Energy lowered interest costs on long-term debt by taking advantage of declines in market rates and refinancing opportunities. Despite a \$15.4 million decrease in revenues attributable to the rate decreases, Hoosier Energy produced an operating margin of \$9 million, up from \$5.8 million in 1994.

2. Wabash Valley Power Association

On May 23, 1985, Wabash Valley filed a Petition for Reorganization under Chapter 11 of the Federal Bankruptcy Code. The filing resulted from Wabash Valley's inability to repay approximately \$525 million borrowed from the Federal Financing Bank and the Rural Utilities Service for investment in the canceled Marble Hill nuclear project.

⁶ Due to the lack of available financial data and the large number of distribution cooperatives, the review of financial status will be limited to Hoosier Energy (HE) and Wabash Valley Power Association. The data for this section comes from the 1995 annual report and a Standard & Poor's Credit Report for HE and the 1995 annual report for WVPA.

On May 28, 1985, the Bankruptcy Court authorized Wabash Valley to operate as a debtor in possession and manage its business and property with full power and authority consistent with provisions of Chapter 11 of the Bankruptcy Code until further order from the Bankruptcy Court.

As of December 31, 1995, Wabash Valley continues to operate as a debtor in possession consistent with the provisions of Chapter 11. The confirmed Plan of Reorganization will be implemented once it becomes final and non-appealable. RUS has filed a petition with the U.S. Supreme Court for hearing on the bankruptcy.

D. Competition and Financial Status

It is too early in the electric utility industry restructuring process to predict what the financial status of Indiana's utilities will be in the future. The utilities are devising strategies to place themselves in the best possible position for operating in a more competitive industry.

Financial services, investor services and rating agencies are also trying to understand how the changes in the industry will effect the financial status of utilities. Stranded costs, disaggregation, mergers and acquisitions and competitive position have all been analyzed in a effort to determine winners and losers in the new competitive industry. Moody's Investors Services was one of the first organizations to try to get a handle on stranded costs when they first became an issue. Moody's and Fitch Investor Services have both tackled the effects of unbundling on utilities' financial status. Standard and Poor's and Duff & Phelps have tried to determine the benefits of merger and acquisitions. Fitch Investor Services has tried to devise a competitive indicator to analyze utilities. While all of these reports provide insights to the changes in the electric utility industry and the effects on individual companies, no definitive criteria has been established for determining future success in the industry.

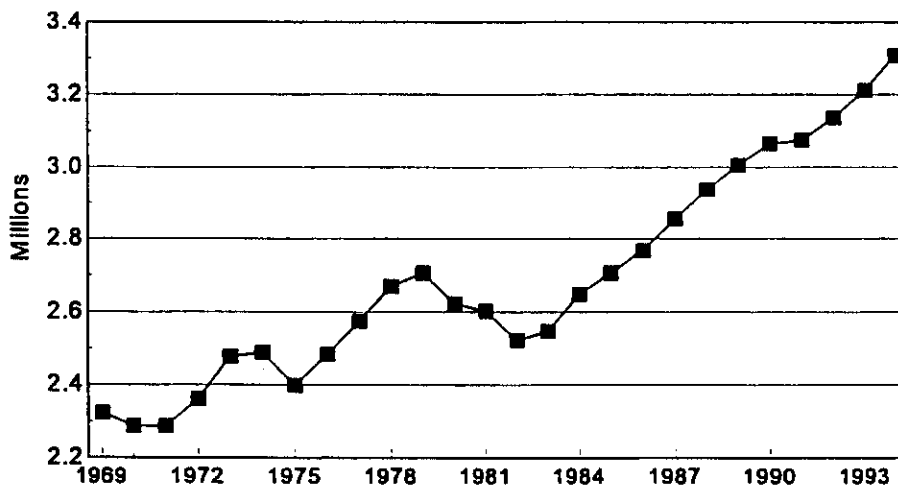
VI. INDIANA'S ECONOMY AND THE ROLE OF ELECTRICITY

After lagging the rest of the nation throughout most of the 1970s and 1980s, the economies of the Midwestern states, and Indiana in particular, have grown faster than the national average since the end of the 1990-1991 recession. Improvements in labor productivity, rapid growth in export markets and an emphasis on civilian manufactured durable products have been critical elements for this success. However, an often overlooked factor has been the relatively low cost of energy, particularly electricity, in Indiana in comparison with the rest of the nation. Indiana firms and consumers have been able to count on reliable and low cost energy, especially since the end of the energy crises in the 1970s and the resolution of the Bailey and Marble Hill nuclear power plant problems.

A. Trends in Employment and Income and Indiana's Relative Ranking

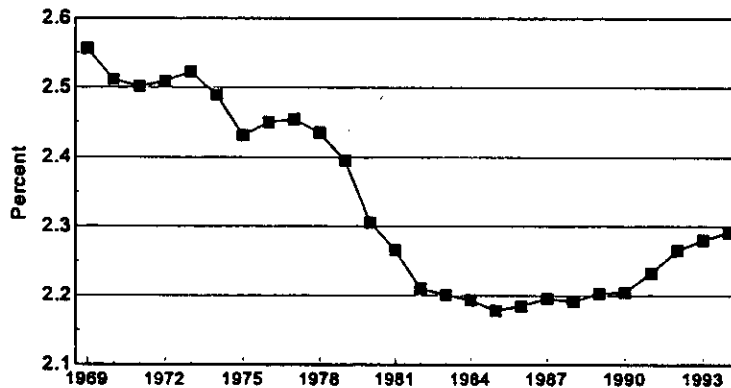
As shown in Figure VI.1, the economy of Indiana was hit hard by the 1970, 1974-75, and 1980-82 recessions. These devastating downturns in the economy reduced the state's share of total U.S. employment from nearly 2.6% in 1969 to 2.2% in the mid-1980s (See Figure VI.2). Since then the state's share of national employment has risen steadily to its current 2.3% level.

FIGURE VI.1: EMPLOYMENT IN INDIANA



Source: Jaffee, B.L. And Lyon, T.P., "Competition in Energy Markets: Potential Impacts on Economic Development," Appendix A, August 1996.

FIGURE VI.2: INDIANA'S SHARE OF TOTAL U.S. EMPLOYMENT

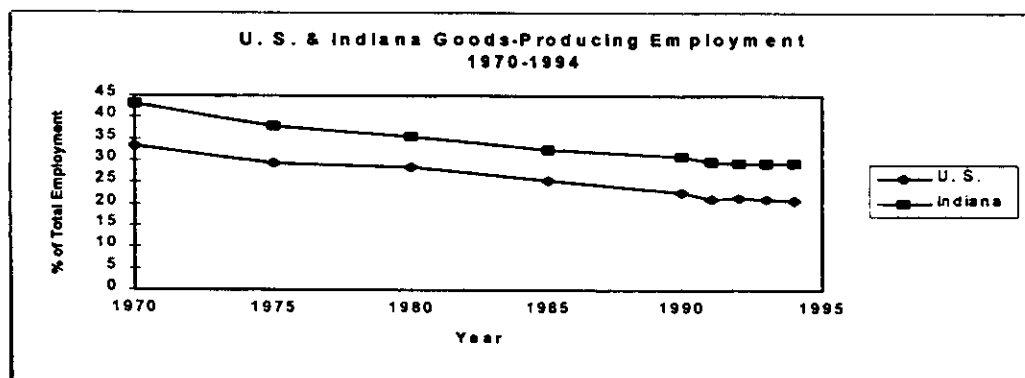


Source: Jaffee, B.L. And Lyon, T.P., "Competition in Energy Markets: Potential Impacts on Economic Development," Appendix A, August 1996.

At both the national and state levels there has been a gradual, but steady, shift in the composition of employment from "goods-producing" to "service-producing." Goods-producing employment at the national level declined from 33.3% of the total in 1970 to 20.8% in 1994. The decline in Indiana was from 43.2% to 29.4% in the same time period. These trends are illustrated in Figure VI.3, but that diagram also indicates that Indiana has continued to maintain a greater reliance on goods producing employment than the nation as a whole.

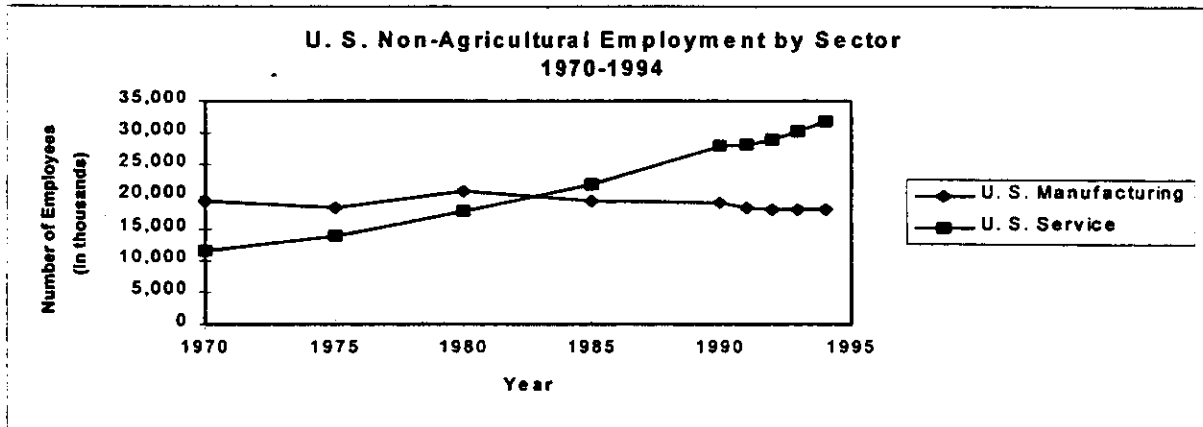
Manufacturing is the largest component of goods-producing employment and is an area where Indiana has an employment share quite different from the nation as a whole. In 1994, 24.4% of Indiana's non-agricultural employment was in manufacturing, a proportion of the labor force 53% above the national average of 15.9%. Figures VI.4 and VI.5 show the national and state employment shifts over time for the manufacturing and service components of employment.

FIGURE VI.3:



Source: Statistical Abstract of the United States.

FIGURE VI.4:



Source: Statistical Abstract of the United States, 1995, Table No. 666.

FIGURE VI.5:



Source: Statistical Abstract of the United States, various years.

While these figures show similar trends, they also indicate that there has been less of a shift away from manufacturing towards services in Indiana than for the U.S. as a whole. Clearly, Indiana's economic health is much more dependent on a growing and competitive manufacturing sector than most states in the country.

Thus the challenge facing policy and decision makers in the state is to create a climate to continue the recent trends. In their analysis of the recent resurgence of the Midwest economy, Bill Bergman and William Strauss⁷ of the Federal Reserve Bank of Chicago focus on productivity improvements, growing international competitiveness and an industrial structure emphasizing durable goods, a sector of the economy that has been growing faster than the national average in recent years. However, they conclude by mentioning key external conditions, which can be affected by policy decisions, that have been important for strong economic growth: declining long-term interest rates, an improved climate for international trade, "and perhaps most important, the fact that energy prices have declined to some of their lowest levels (in real terms) in the past three decades." This conclusion is reinforced by recent work by Bernard C. Beaudreau⁸ who found that 79% of the growth in manufacturing is associated with growth in electric power consumption, which, in turn, depends on prices and availability.

B. Trends in National & State Electricity Prices: Indiana's Competitive Advantage

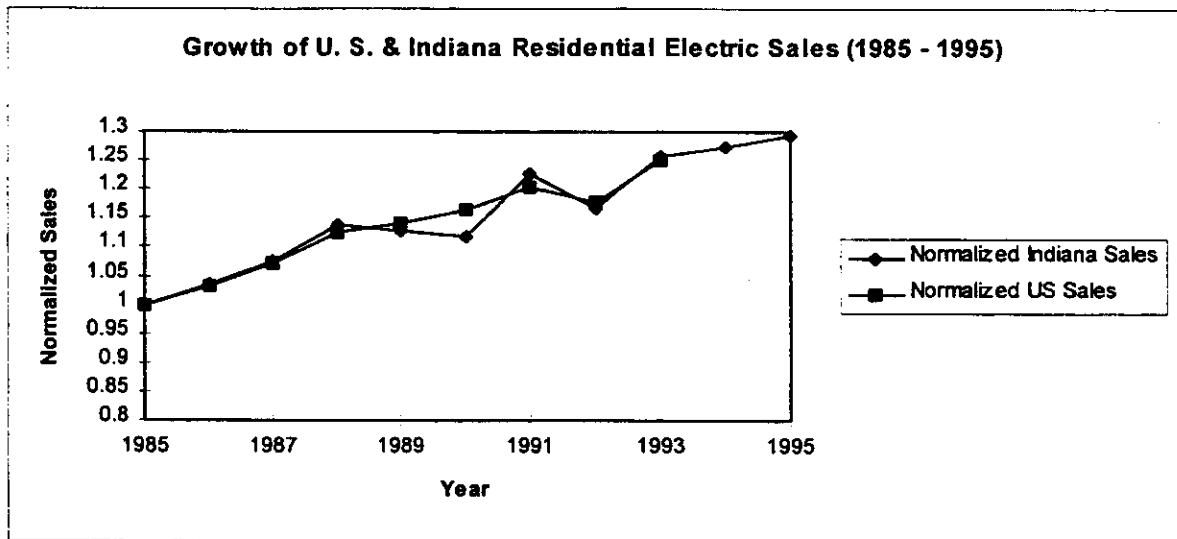
Figures VI.6, VI.7, and VI.8 compare the U.S. and Indiana rates of growth in electricity sales in the last decade. Indiana's residential and commercial sales growth rates have roughly mirrored the national trends since 1985. However, the situation is quite different for industrial electricity sales. After lagging the nation between 1985 and 1987, Indiana's industrial sales growth has been well above the national trend since then.

While usage has increased, prices have declined. The trend is clear in Tables VI.1 and VI.2. At the national level inflation adjusted prices per kWh have dropped 17.6%. The decline was 14.1% for the residential sector, 19.5% for the commercial sector, and an impressive 26.4% for the industrial sector. At the state level, average inflation adjusted prices per kWh declined 32.8% between 1985 and 1994. The declines were 28.4% for the residential sector, 33.3% for the commercial sector, and 34.0% for the industrial sector. These declines in real electricity prices have been a large benefit to major industrial users of electricity and the developers and manufacturers of electricity-using equipment and appliances: both important sectors of the Indiana economy.

⁷ Bill Bergman and William Strauss, "The Midwest Economy: Still a Swan," *Chicago Fed Letter*, April 1995.

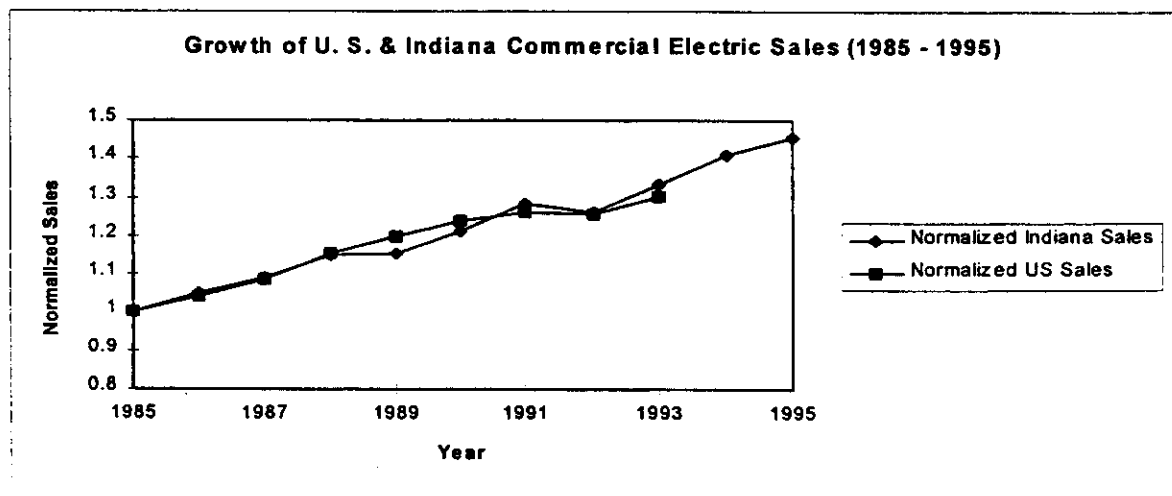
⁸ Bernard C. Beaudreau, "The Impact of Electric Power on Productivity: A Study of U.S. Manufacturing 1950-84," *Energy Economics* 1995, volume 17, Number 3.

FIGURE VI.6:



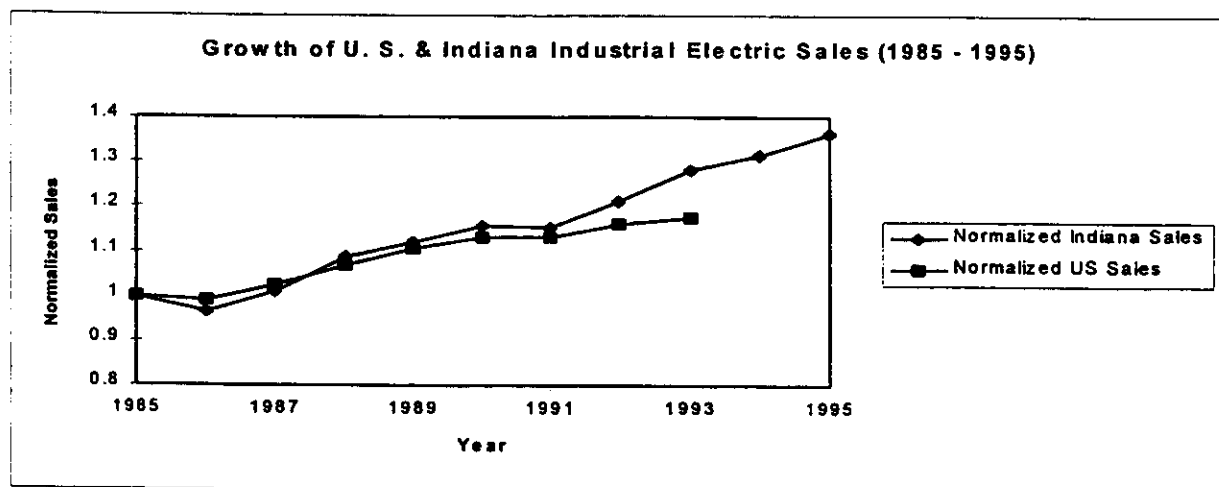
Sources: U.S. Energy Information Administration, *Annual Energy Review*
State Utility Forecast Group, *Indiana Electricity Projections 1994*

FIGURE VI.7:



Sources: U.S. Energy Information Administration, *Annual Energy Review*
State Utility Forecast Group, *Indiana Electricity Projections 1994*

FIGURE VI.8:



Sources: U.S. Energy Information Administration, *Annual Energy Review*
State Utility Forecast Group, *Indiana Electricity Projections 1994*

TABLE VI.1:
U.S. Average Price of Electricity Sold (1985-1993)
(based on 1987 dollars)

Year	Commercial	Average Price (cents/kWh)		Total
		Residential	Industrial	
1985	7.7	7.8	5.3	6.8
1986	7.4	7.6	5.1	6.6
1987	7.1	7.4	4.8	6.4
1988	6.7	7.2	4.5	6.2
1989	6.6	7.0	4.3	6.0
1990	6.4	6.9	4.1	5.8
1991	6.4	6.8	4.1	5.7
1992	6.4	6.8	4.0	5.6
1993	6.2	6.7	3.9	5.6

Source: U.S. Energy Information Administration, *Annual Energy Review*

TABLE VI.2:
INDIANA AVERAGE PRICE OF ELECTRICITY SOLD (1985-1994)
(based on 1987 dollars)

Year	Commercial	Average Price (cents/kWh)		Total
		Residential	Industrial	
1985	6.6	7.4	5.0	6.1
1986	6.8	7.5	5.1	6.3
1987	6.6	7.2	4.6	6.0
1988	6.4	6.8	4.4	5.7
1989	5.4	6.4	4.0	5.1
1990	5.1	6.0	3.8	4.8
1991	4.9	5.6	3.6	4.6
1992	4.6	5.6	3.5	4.4
1993	4.4	5.3	3.3	4.2
1994	4.4	5.3	3.3	4.1

Source: State Utility Forecast Group

C. Conclusions

Indiana's economy lagged behind the nation's growth rate for much of the last 25 years. The trend has changed. In the last five years the state's economy has rebounded with strong growth in manufacturing being especially notable. However, the industrial sector in Indiana is concentrated on a relatively small number of industries, many of which use large amounts of electricity and depend on low electricity prices to remain competitive.

While electricity is an important cost element for many of this state's industries, labor cost and productivity, taxes, raw material costs, transportation and communications factors, as well as product demand are other critical elements of a firm's success or even survival. Electricity price, availability, and service reliability are important components that affect economic growth. The challenge facing policymakers is to assure that as the electricity market becomes more competitive, and competition and deregulation schemes are instituted in other states and at the national level, Indiana retains its relative advantages in these three areas.

VII. HISTORICAL OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY

In 1935 the Federal Power Act (FPA) was passed, creating the Federal Power Commission (FPC), the predecessor of the Federal Energy Regulatory Commission (FERC). The FPA provided broad authority for the FPC, and ultimately the FERC, to regulate the interstate transmission of electricity for subsequent resale to consumers. Title I of the FPA was the Public Utility Holding Company Act (PUHCA). PUHCA was passed in response to the abuses and virtual collapse of the electric utility industry in the early 1930s.

In 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA) to promote small and renewable generating technologies. The FERC's rules for implementing PURPA allowed a powerful new form of competition in generation to begin. Under these rules, utilities would have to buy power from non-utility generators at "avoided cost," or what it would cost the utility to generate the same amount of power.

In 1992 Congress passed the Energy Policy Act (EPAct), which was designed to encourage competition by removing some of the impediments in PUHCA. While much of the debate in the industry and in Congress centered on the creation of "exempt wholesale generators," the most significant item in the 1992 law was the opening of the electric utility transmission grid. This made it possible to move wholesale power from the seller to the buyer through an intervening electric utility grid, thus opening new wholesale markets. Because of this access to the monopoly grids, a new type of company entered the power supply field: the power marketer. Power marketers own neither generation nor transmission; they are classic brokers who facilitate deals between buyer and seller and take a piece of the transaction.

In this climate of increasing competition, mergers of electric utilities have become more frequent (see Table VII.1). In the past a merger was usually the result of a large utility taking over a smaller utility, or a financially healthy utility buying out a financially weak utility. Today mergers are more a partnership of equals. Utilities are merging to cut operating costs and to provide themselves access to more markets as competition develops. One of the best examples of a merger of equals was the highly publicized merger of PSI and Cincinnati Gas and Electric to form Cinergy.

Most mergers have occurred between contiguous utilities. Savings are anticipated from staff reductions and the sharing of low-cost generation assets. However, analysts have noted that the announced savings are fairly small. For example, savings in the proposed Baltimore Gas &

Electric/Potomac Electric Power merger amount to 2.8% of annual revenue.⁹ Furthermore, as many public utilities commissions are requiring that a portion of the savings be passed on to ratepayers, stockholders will see little benefit from these cost reductions.

TABLE VII.1:
RECENT MAJOR MERGERS OF
VERTICALLY INTEGRATED ELECTRICITY DISTRIBUTION COMPANIES
1991-1996

Pre-Merger Utilities	Post-Merger Utility	Total Customers	Value of Transaction	Year Completed
Public Service of New Hampshire/Northeast Utilities	Northeast Utilities	1,750,000	\$2.3 billion	5/91
Kansas Power & Light/Kansas Gas & Electric	Western Resources	1,570,000	\$1 billion	4/92
Gulf States Utilities/Entergy	Entergy	2,400,000	\$2.28 billion	12/93
Iowa-Illinois Gas & Electric/Midwest Resources	MidAmerican Energy	630,000	\$842 million	7/94
PSI Resources/Cincinnati Gas & Electric	Cinergy	1,300,000	\$1.55 billion	10/94
Portland General/Enron	Not Settled	650,000	\$2.1 billion	Still Pending
Kansas City Power & Light/UtiliCorp	Maxim Energies	2,200,000	\$3.00 billion	Still Pending
Potomac Electric Power/Baltimore Gas & Electric	Constellation Energy	1,800,000	\$3.07 billion	Still Pending
Wisconsin Energy/Northern States Power	Primergy	2,300,000	\$3.04 billion	Still Pending
Central Illinois Power/Union Electric	Ameren	1,400,000	\$1.24 billion	Still Pending
WPL Holdings/IES Industries/Interstate Power	Interstate Energy	850,000	\$1.21 billion	Still Pending
Southwestern Public Service/Public Service Co. of Colorado	New Century Energies	1,500,000	\$1.02 billion	Still Pending
Puget Sound Power & Light/Washington Energy	Puget Sound Energy	1,100,000	\$488 million	Still Pending

⁹ "Save a Nickel, Save a Dime: Is One Merger as Good as Another?", *Public Utilities Fortnightly*, February 15, 1996, p. 54, and Robert J. Michaels, "Electric Utility Mergers: The Answer or The Question?" *Public Utilities Fortnightly*, January 1, 1996, pp. 20-23.

A. FERC Initiatives

In response to EPAct, the FERC proposed a series of initiatives designed to encourage competition, particularly in the wholesale markets. The FERC opened all proposals to comment by interested parties. The IURC responded to all the FERC initiatives discussed in this section. Following is a summary of the FERC's proposals and the current status of each.

TABLE VII.2: FERC INITIATIVES

Title	Docket Number	Date of IURC Response
Inquiry Concerning the Federal Energy Regulatory Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act	RM93-19-000 Issued:6/30/93 Order:10/26/94	November 3, 1993
Notice of Proposed Rulemaking Recovery of Stranded Costs by Public Utilities and Transmitting Utilities	RM94-7-000 Issued:6/29/94	December 7, 1994
Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act	RM94-20-000 Issued:10/26/94	February 22, 1995
Request for Comments Regarding Real-Time Information Networks	RM95-9-000 Issued:3/29/95 Order:4/24/96	June 28, 1995
Notice of Proposed Rulemaking Regarding Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services By Public Utilities Supplemental Notice of Proposed Rulemaking Regarding Recovery of Stranded Costs by Public Utilities and Transmitting Utilities	RM95-8-000 Issued:3/29/95 Order:4/24/96 RM94-7-000 Issued:3/29/95 Order:4/24/96	August 5, 1995
Notice of Inquiry Merger Policy Under the Federal Power Act	RM96-6-000 Issued: 1/31/96	May 1, 1996

Transmission Pricing

On June 30, 1993, the FERC issued a Notice of Inquiry on transmission pricing. Extensive comments were submitted by regulatory agencies, utility companies and others. The FERC issued a policy statement on transmission pricing October 26, 1994, which includes five principles that provide the foundation for the FERC's analysis of transmission pricing filings. The FERC distinguishes transmission pricing filings as either "conforming" or "non-

conforming." Conforming filings generally follow a traditional original cost-based method. Innovative pricing methods are considered non-conforming. To date several non-conforming rates have been proposed to the FERC but none have been approved. All currently approved transmission pricing tariffs are based on traditional rate-making methodology.

Stranded Costs

On June 29, 1994, the FERC issued the Notice of Proposed Rulemaking on Recovery of Stranded Costs by Public Utilities and Transmission Utilities. The FERC later incorporated the stranded cost NOPR into the notice of proposed rulemaking that became known as the "MegaNOPR." Order No. 888 was issued April 24, 1996, on this NOPR.

Industry Restructuring (Poolcos)

A Notice of Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act was issued October 26, 1994. This inquiry explored the potential advantages and disadvantages of encouraging power pools to increase competition in the wholesale power markets. In its response to this notice, the IURC stated that power pools should be considered in conjunction with the overall restructuring of the electric utility industry. The FERC has not taken any further action on this notice of inquiry.

Real-Time Information Networks (RINs)

On March 29, 1995, the FERC issued its Open Access NOPR (MegaNOPR). In conjunction with that NOPR it issued a notice of technical conference and request for comments on Real-Time Information Networks (RINs). In its response, the IURC voiced its concern that RINs alone would not be adequate to eliminate the advantage a utility's wholesale marketing affiliate may have in scheduling and purchasing transmission capacity; other safeguards would be needed. On December 13, 1995, the FERC issued a Notice of Proposed Rulemaking on Real-Time Information Networks and Standards of Conduct. While much of the NOPR discussed the technical aspects of the design and operation of RINs, two questions specifically addressed whether a formal standard of conduct would adequately provide a "level playing field" for all users of a transmission system. The IURC focused its response on those two questions, echoing many of its concerns from its response to the original inquiry. The FERC issued Order No. 889 on April 24, 1996, in response to this NOPR.

Open Transmission Access (MegaNOPR)

On March 29, 1995, the FERC issued the Notice of Proposed Rulemaking Regarding Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services By Public Utilities. This proposal outlined rules and procedures necessary to promote wholesale competition. The IURC made a detailed response to this NOPR. Theoretically, the IURC endorsed the FERC's efforts to promote wholesale competition but explained that legal and jurisdictional hurdles would have to be overcome before open transmission access would really provide increased competition. The FERC's Order No. 888 was issued April 24, 1996, in response to this NOPR.

Merger Policy

On January 31, 1996, the FERC issued a Notice of Inquiry Concerning Commission's Merger Policy Under the Federal Power Act. Many observers of the electric utility industry have suggested that the move toward competition will encourage utilities to merge in order to gain market power. Many have criticized the FERC for not adequately reviewing proposed mergers between utilities for market power consequences. With this notice the FERC formally solicited comments on this issue. Comments were due in April 1996. The FERC has not taken any further action on this notice at this time.

B. States and Competition

While the FERC is promoting competition for wholesale markets, state commissions and legislative bodies are at various stages of addressing competition for retail markets.

California was the first to call for competition on the retail level. In April 1994, the California Public Utilities Commission (CPUC) issued its proposal for initiating retail wheeling on a very aggressive time schedule. The comprehensive restructuring plan for the California utilities sparked extensive debate on the form and implementation of retail competition. Participants in the California debate were the first to consider the concepts of poolco and bilateral models.

Michigan was also an early leader in the consideration of retail competition. The Michigan Public Service Commission proposed the first retail competition pilot program involving Detroit Edison Company and Consumers Power Company in 1994. Implementation of the experiment was pegged to each company's next supply-side solicitation for new capacity.

Only industrial retail customers were eligible to participate in the program; this led to protests by representatives of small consumers groups.

Since their original announcements on retail competition, both California and Michigan have encountered a variety of legal and regulatory problems. Both states are still moving toward retail competition but their aggressive pace has slowed. A recent review of Detroit Edison's integrated resource plan indicates that the utility may be forced to begin its retail experiment in the near future. In May 1996, California's three investor-owned utilities filed for FERC approval of an independent system operator and a statewide power exchange as mandated by the CPUC's December 20, 1995, restructuring order. On August 31, 1996, California lawmakers approved an omnibus electric restructuring package, Assembly Bill 1890, for deregulating California's power industry and opening generation to competition by January 1998. This Bill codifies the CPUC's restructuring order into law. The Bill addresses two key concerns relative to electric utility restructuring: ensuring that small ratepayers gain immediate benefits from a competitive electric industry along with utilities and large power users; and maintaining the reliability of the electric system.

In 1996, two of the most active states in the implementation and operation of retail competition have been New Hampshire and Illinois. Both have begun pilot programs that include all types and sizes of retail customers.

On April 17, 1996, the New Hampshire state legislature adopted House Bill 1392, which requires utilities to open their service territories to retail competition by January 1, 1998. The Bill also gave the New Hampshire Public Utilities Commission (NHPUC) strong powers to develop utility restructuring plans and set initial stranded investment recovery levels. With this legislative authority the NHPUC initiated plans for a retail competition pilot program. The program covers 50 MW of retail load; 33 MW coming from Public Service New Hampshire. On May 1, 1996, utilities and independent power marketers began competing to sign up retail customers designated to participate in the state's retail wheeling pilot program. Designated customers included small homeowners, large manufacturing plants, hospitals and newspapers across the state. Statewide, about 16,500 retail customers with a total load of 50 MW are participating in the pilot. Delivery of electricity for some of the pilot program customers began as planned on May 28, 1996, but disputes between the utilities, NHPUC and the FERC about transmission tariffs delayed deliveries for most customers. The FERC has agreed to waive some of the requirements of the Order 888 open-access tariffs so that the pilot program may proceed. All pilot program customers were receiving electricity deliveries by July 1, 1996.

On April 25, 1996, a retail competition experiment was begun in Illinois. The experiment covers 25 industrial customers, residential and small businesses in three communities, a 25-acre greenfield site and a shopping mall. As of April 30, 1996, seven Illinois Power and four Central Illinois Light industrial customers have opted for alternative power suppliers. About 200 residential customers have signed up with alternative power suppliers; delivery of non-system power was expected to begin on May 8, 1996. Participating utilities will file a report with the Illinois Commerce Commission on the status of the experiment in September 1996. Neither the New Hampshire nor the Illinois retail competition experiments have been operating long enough to form any conclusions on the viability of retail competition.

Other states, including Indiana, have taken a more cautious approach to retail competition. The Ohio, Indiana and Kentucky commissions have all been monitoring the retail competition activities in other states. Both the Ohio and Indiana commissions have led informal forums for the discussion of competitive issues. These forums have included participants from the utilities, consumer groups, labor unions, independent power producers, power marketers, other regulatory agencies and educational institutions. These forums have allowed a productive exchange of ideas on the benefits, costs and implementation of retail competition.

In general, commissions and legislatures in states with high electricity prices tend to be actively considering retail competition. In states with low-cost electricity, commissions and legislatures have taken a more cautious, wait-and-see approach to competition. In these states it may be the low-cost utilities pushing for competition. Several Indiana utilities have embraced the concept of competition and are preparing themselves to participate in a more competitive industry. Cinergy has been particularly active in the retail competition arena. Cinergy Services, Inc. will supply 2 MW to A.E. Staley's corn processing plant in Decatur, Illinois as part of the Illinois Commerce Commission's retail wheeling experiment. In June 1996, Cinergy announced an agreement with Nordic Electric, a Michigan-based power aggregator, to supply power to seven Michigan industrials. Nordic has filed a petition with the Michigan Public Service Commission seeking approval to provide the power to the industrial customers. This petition is still pending.

VIII. STRUCTURAL APPROACHES TO INCREASING COMPETITION

A. FERC Actions in the Wholesale Power Market

The Federal Energy Regulatory Commission has begun implementing a number of actions designed to increase the level of competition in the bulk (or wholesale) power market. Primary attention has been focussed on the imperative of providing all generators open access to bottleneck facilities like transmission. By ensuring open access to the transmission system, it is hoped that full and fair competition among generators will result in a more competitive bulk power market.

The FERC has decided that functional unbundling of wholesale generation and transmission services is necessary to implement non-discriminatory open access to transmission. In terms of the recent FERC Order 888, functional unbundling means the following:

- (1) a public utility must take transmission services (including ancillary services) for all of its new wholesale sales and purchases of energy under the same tariff of general applicability as do others
- (2) a public utility must state separate rates for wholesale generation, transmission, and ancillary services
- (3) a public utility must rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power.¹⁰

The FERC believes that the above requirements are essential to ensure that public utilities provide non-discriminatory transmission service. It argues that these requirements will give utilities an incentive to file fair and efficient rates, terms and conditions, because they will be subject to those same rates, terms and conditions.

¹⁰ Federal Energy Regulatory Commission, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Final Rule, Order No. 888, Docket Nos RM95-8-000 and RM94-7-001, April 24, 1996, p. 57.

The FERC will also require an additional safeguard of a strong code of utility conduct. These standards are proclaimed in Order No. 889, Final Rule, Open Access Same-Time Information System (OASIS) (formerly Real-Time Information Networks) and Standards of Conduct, issued April 24, 1996. Briefly, the standards of conduct are designed to prevent employees of a public utility (or any of its affiliates) engaged in marketing functions from obtaining preferential access to OASIS-related information or from engaging in unduly discriminatory business practices. Companies are required to separate their transmission operation/reliability functions from their marketing/merchant functions and prevent system operators from providing merchant employees and employees of affiliates with transmission-related information not available to all customers at the same time through public posting on the OASIS.

FERC believes that functional unbundling and a code of conduct will place the vertically integrated utilities on a "level playing field" with other power producers in the generation market. The vertically integrated utility will be prohibited from using its control of the transmission system to block transactions of other power producers or favoring its own generation in a transaction. One way the utility could do this is by exaggerating its reliability concerns associated with a particular power transaction.

Even with these and other safeguards, some industry participants believe that functional unbundling will not be sufficient to ensure non-discriminatory open access to transmission. Critics of functional unbundling argue that the utility will still favor itself on issues related to transmission planning, capital investment and operation and maintenance and replacement costs.¹¹

A number of means of dealing with these concerns have been put forward, including corporate unbundling (selling off generation into separate companies) and the development of independent entities to operate transmission systems.

B. The Independent System Operator

Most industry participants believe that as non-utility generation and transmission access increases, responsibility for coordinating the overall power system should be separated from the traditional control area utilities. Services now routinely provided by utilities would increasingly

¹¹ Ibid, p 55.

have to be unbundled and established by contract or other agreements among generators, power purchasers and transmission owners/operators. The basic institutional construct central to the debate is the independent system operator (ISO).

Numerous states are considering allowing retail customers direct access to the generation market in order to reduce the cost of electricity and to offer more choices to the consumer. Many participants agree there may be benefits from greater customer choice and a competitive generation market, but they also fear that reliability may be jeopardized and off-setting costs may be incurred due to less coordination of the production and delivery of electricity.

An ISO is generally thought of as an independent entity or institution that would control the transmission grid; that is, the transmission assets and whatever generation is needed for reliability. To ensure reliability, the ISO would administer operating criteria for the necessary ancillary services. Ancillary services identified by the FERC include the following: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and the economic dispatch of plants); contractual arrangements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves). Other potential responsibilities for the ISO vary according to the particular future industry structure under discussion.

C. The Midwest ISO

In February 1996, a group of six utilities¹² announced the formation of a group to pursue the development of an Independent System Operator (named the Midwest ISO), whose goal is to provide electricity generators throughout the U.S. with open access to the members' transmission systems. Currently, all five major Indiana IOUs and Wabash Valley Power, Hoosier and IMPA have signed the statement of principles and are participating in discussions to form the Midwest ISO. See Table VIII.1 for a list of participants in the Midwest ISO discussions as of July, 1996, and the map that follows which shows the service territories of the participants.

Participants in the Midwest ISO group intend to file operating plans with FERC by the first quarter of 1997. Partial operation will likely start in 1998. The Midwest ISO would be a

¹² The six utilities are American Electric Power Company, Cinergy, Centerior Energy, Detroit Edison, Northern Indiana Public Service Company, and Wisconsin Electric.

non-profit organization, independent of transmission owners, with three major functions: operations, planning and administration.

Four factors have been cited as the impetus for the formation of a Midwest ISO.¹³ One catalyst is to provide non-discriminatory open access to the regional transmission system. A second factor is the provision of uniform transmission pricing. By accomplishing the first two components, the Midwest ISO hopes to solve the problem of "pancaked" transmission rates. This occurs when an entity wants to wheel power through, say, three utilities' transmission systems, and must pay a user fee to each utility for the use of its transmission system. This can inhibit otherwise beneficial power exchanges. By forming an ISO and charging one fee for the entire regional transmission system, more trades can occur. A third factor motivating the Midwest ISO's formation is transmission and system security. The fourth element is to facilitate coordinated planning of the transmission network.

Although the Midwest ISO would be an independent entity, each utility would retain ownership of its transmission assets. The ISO management would report to a Board of Directors, who may include: transmission owners, transmission customers, and third parties. An Advisory Board of users may be established, and incentives may be established for lowering costs, reliability and innovation.

Four major operational functions that the Midwest ISO will perform are transmission operations, transmission security, bulk power security and inter-ISO cooperation.

The Midwest ISO is not a "fully developed" ISO, in the sense that many control area functions will still be performed by each local utility. Some of these functions are: the maintenance and physical operation of transmission facilities; the restoration of transmission service after an outage; economic generation dispatch; local generation/load balance and frequency; planning for local transmission facilities; and the construction of transmission facilities.

Because not all transmission planning and operations functions are being turned over to the Midwest ISO, some industry observers contend that millions of dollars in efficiency losses

¹³ Much of the following discussion is from Falcone, CA, "A Midwest Independent System Operator," presented at the Annual Midwest Power Market Conference, Chicago, IL, April 19, 1996.

will still be present each year.¹⁴ Also, some observers criticize the members of the ISO for not fully divesting of their transmission assets, in order to fully separate the merchant function from the operational function.¹⁵ Obviously, in the early stages of such a significant change in industry structure, no one can truly predict what the results will be.

Table VIII.1:

MIDWEST INDEPENDENT SYSTEM OPERATOR - MEMBERSHIP AS OF JULY 1996

1. American Electric Power Company	12. Indianapolis Power and Light Company
2. Big Rivers	13. Kentucky Utilities Company
3. Centerior Energy	14. Louisville Gas & Electric Company
4. Central Illinois Public Service	15. Michigan Public Power Association
5. Cinergy	16. Northern Indiana Public Service Company
6. Commonwealth Edison	17. Southern Illinois Power Cooperative
7. Detroit Edison	18. Southern Indiana Gas and Electric Company
8. East Kentucky Power	19. Wabash Valley Power Association
9. Hoosier Energy Rural	20. Wisconsin Electric
10. Illinois Power	21. Wisconsin Public Service
11. Indiana Municipal Power Agency	22. Union Electric

¹⁴ For example, see "The Midwest ISO: The Next Generation," editorial, The Electricity Journal, April 1996, p. 89.

¹⁵ "AEP, Cinergy, Centerior, Detroit Ed, NIPSCO, and WEPCO Move to form ISO," Electric Utility Week, McGraw-Hill Co., February 19, 1996, p. 4.

Midwest Independent System Operator



IX. ALTERNATIVE FORMS OF UTILITY REGULATION¹⁶

Historically, the vertically integrated, monopoly utility has been regulated through cost-of-service ratemaking (COSR). With the advent of increased competition, other forms of regulation may be necessary and more appropriate. These alternative forms are referred to as incentive regulation or performance-based regulation (PBR). The main difference between COSR and PBR is that under COSR prices track costs directly while under PBR the direct link between costs and prices is severed. PBR may work better in a partially competitive marketplace where the same facilities provide service to monopoly and competitive markets. Well-designed PBR plans encourage utilities to reduce costs, and allow greater freedom to meet the prices of competitors quickly and effectively while protecting core customers from cross-subsidization. The potential benefits of alternative forms of regulation were acknowledged by the Indiana General Assembly when it passed Senate Enrolled Act 637 in 1995, codified as IC 8-1-2.5. This statute enables the IURC to consider such alternative ratemaking plans.

PBR can entail either targeted incentives, or broad, corporate-wide incentives. Broad-based incentive regulation focuses on general cost-effectiveness, and essentially includes all costs under the utility's control. Targeted incentives focus on specific parameters of utility performance, such as the fuel efficiency and reliability of specific generation units. The scope of targeted incentives is seen by most to be too limited, because the utility's behavior can be distorted by efforts to take advantage of the new incentive structure. For example, if a utility had only an incentive to keep the performance of a generating plant high, it could spend a huge amount of resources to do that, at the detriment of other areas of company performance, such as service quality or conservation programs. Although targeted incentives have a long history, there is very little empirical evidence showing that these incentives increase the overall efficiency

¹⁶ Sources for this section include: Ackerman, ET, A Primer on Performance-Based Regulation, Edison Electric Institute, for the Joint NARUC/EEI Seminar: "Regulating in a Transitional Environment," Providence, Rhode Island, April 19, 1995.

Hill, LJ, A Primer on Incentive Regulation for Electric Utilities, Oak Ridge National Laboratory, ORNL/CON-422, October 1995.

Comnes, GA, Stoft S. Greene N. Hill LJ, Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource-Planning Issues Volume I, Lawrence Berkeley Laboratory, LBL-37577, November 1995.

performance of utilities.¹⁷ Consequently, the type of PBR plans proposed today generally are the broad-based variety.

A. Cost-of-Service Ratemaking

Cost-of-service ratemaking allows an electric utility the opportunity to charge rates that recover all of their operating costs and in addition a return of and on their investments in power plants, power lines and other assets. This involves a two-step process in a rate case. First, the commission determines the total amount of annual revenues needed to maintain the utility's financial viability. Operating, depreciation and tax expenses are determined, along with a rate-of-return on the rate base that is sufficient to compensate the owners of capital (stockholders and creditors) for their investment, and large enough to attract new capital.

The second step is to allocate the required revenues via a rate structure for the various classes of customers. From this cost allocation process, the rates, or prices for customers are set.

Historically, advocates of COSR contend it has worked fairly well to regulate monopoly utility firms for the following reasons: first, it is relatively straightforward since it is based on data that is easy to measure. Second, reliability is encouraged since utilities earn an additional return on every dollar they invest in utility plant. Third, COSR should ensure a fair return on a utility's investment; neither confiscating it nor allowing too high a return.

However, other observers point to the failings of COSR. Chiefly, they argue that the direct link between a utility's costs and revenues leads to detrimental results. Under COSR there is a reduced incentive to reduce costs (except for regulatory lag, discussed later). Additionally, as competition increases it becomes increasingly difficult to allocate common costs between different services in a COSR framework. This cost allocation problem may increase the administrative costs of COSR.

¹⁷ See Berg SV and Jeong J, "An Evaluation of Incentive Regulation for Electric Utilities," Journal of Regulatory Economics, 3(1):45-55 and Berg SV and Jeong J, "An Evaluation of Incentive Regulation: Corrections," Journal of Regulatory Economics, 6(3):321-328.

B. Description of Alternative Ratemaking Mechanisms

1. Price Cap Regulation

Price cap regulation explicitly breaks the direct link between a utility's costs and the prices it charges. Under price cap regulation (PCR), a weighted average ceiling price is set for one or several market baskets of services provided by a utility.

A price cap mechanism involves four basic steps. The first step involves defining the market baskets and setting benchmark prices. Theoretically, a utility could have as many price caps as it has customers. In practice, however, this is not feasible, so groups or "baskets" of customers are created, combining individual customers into groups. The regulatory objective is to ensure that customers over which a utility has monopoly power are not grouped with those served in competitive markets.

The second step is to protect utilities from costs beyond their control. Consequently, ceiling prices are allowed to increase with some inflation index factor over time.

If an input cost index is chosen (and sometimes even if a price index is chosen), the third step is to include a productivity offset, to account for the gains in input productivity that a utility should achieve through time. This value is often set higher than parties might expect productivity to increase, to act as an incentive for the utility to achieve greater cost reductions.

The last step allows some types of costs to be recovered without being part of the price cap. These are known as Z-factors, and could include such items as stranded costs or regulatory assets. Regulatory assets are items under Statement of Accounting Standards No. 71 that arose when a utility was regulated on a cost-of-service basis and is entitled to collect when changing to a different regulatory model.

The main difference between PCR and COSR is that under PCR, the link between a utility's costs and the prices it can charge its ratepayers is broken. The price cap also gives a utility the flexibility it needs to meet competitors' rates while protecting other customers from cross-subsidization. Under COSR, prices are set for individual services. These prices can be considered both a price floor and a price ceiling. Under price cap regulation, the weighted average ceiling price, as well as the price of individual services, are not also the lowest price the utility may charge. A utility is given flexibility to price below the ceiling to some predefined, lower floor. The marginal cost of providing the service (either short-run or long-run) can be used

as the lowest price the utility can charge for that service. Typically, the procedures for regulatory review of a utility's financial condition also change. Regulatory reviews are conducted at predefined intervals, such as every five years, under PCR. The time interval between regulatory reviews affects the utility's incentives to reduce costs. Generally, the shorter the time interval, the less likely that a firm will take measures to reduce its short- or long-term costs. The longer the interval, the more likely that a firm will reduce costs because it has the possibility of earning more profits.

2. Rate of Return Bandwidth Regulation

When initiating revenue sharing, sliding scale, or rate-of-return bandwidth regulation, it is necessary to first set rates using traditional regulation methods. Then, the utility's earned return on equity (ROE) for a predefined period is allowed to fluctuate in a "band" around a target or authorized return. If the earned return falls outside of the band, then rates are adjusted up or down to get the utility back inside the band. An additional feature of some plans is a sharing mechanism between the ratepayers and the shareholders for returns that fall outside the band. For this type of mechanism, then, the wider the band is, the more incentive a utility has to cut costs and thus increase its ROE without a "fear of over-earning."

3. Revenue Caps

Under a revenue cap, a utility's allowed revenues are capped with an external index. Subject to the cap, the utility is permitted to maximize profits, presumably by minimizing total costs. Most revenue caps are applied to revenues deriving from base rates only. Base rates are determined through a rate case. The formula usually excludes and adjusts for events beyond management's control, while allowing for changes in inflation and productivity. Although base-rate revenues are generally considered fixed with respect to the level of per-customer sales, revenue caps usually allow some adjustment for increases in the number of customers. Revenue caps are usually combined with rate-of-return bandwidth mechanisms to guard against the possible failure of the index to keep returns within acceptable bounds. Although revenue and price caps create the same incentives to minimize costs, they differ significantly in terms of the incentives that they provide for incremental sales. The incentive to maximize sales that exists under price caps does not exist with revenue caps.

In addition to the three basic mechanisms described here, any variation or combination of these can be implemented as well. For example, a common practice is to combine price caps with a form of rate-of-return bandwidth regulation.

C. The Pros and Cons of COSR and PBR

1. Cost-of-Service Ratemaking

The potential changes that PBR would bring should be compared to the present set of incentives inherent in COSR. One criticism of COSR is that the primary source of information for setting rates is the regulated utility itself. Because of the linkage of a utility's rates to its costs, COSR is criticized for promoting inefficient behavior and has been labeled "cost-plus" regulation.

It should be noted that there are several factors which lessen the cost-plus nature of COSR. One of these factors is regulatory lag. In this context, the term regulatory lag does not refer to perhaps its most common connotation, which is the time it takes a rate case to move through a state utility commission. Rather, it refers to the time between rate cases during which prices are fixed. This period, when the utility earns revenue deriving from prices set during the last rate case, serves as an incentive for the utility to minimize costs during this time, since they will keep all of the savings (or alternatively bear all of any increased costs). A second feature of COSR is that the regulator can disallow imprudent costs, which should limit egregious utility behavior. A third factor is that utilities are no longer pure monopolies in many markets. Competitors threaten to take away market share, and this threat limits inefficient behavior to some degree. This is heavily dependent on regulators being able to prevent cross-subsidization of competitive activities with monopoly activities.

2. Performance-Based Ratemaking

Five potential benefits of well-designed PBR mechanisms can be identified:¹⁸ First, PBR may result in better resource efficiency, which is usually measured by productivity. PBR gives a utility a financial stake in improved productivity because the utility can keep a greater share of any cost savings it achieves.

Second, PBR may improve allocative efficiency, which can be defined as maximizing the total value of an economy's output of goods and services. Allocative efficiency is improved when prices for goods and services are set at marginal costs.

¹⁸ p. 6-8, *Ibid*, Comnes, et al.

Third, PBR may result in reduced administrative and regulatory costs. Under COSR, regulators expend considerable effort and expense to bridge the information gap between themselves and the utility. A well-designed PBR mechanism does not attempt to close the information gap, but instead relies on a different set of incentives to ensure better utility performance. In a sense, PBR aligns the interests of shareholders and ratepayers, in that lowering costs and rates benefits consumers, and if the utility can increase its profits at the same time, it is allowed to keep the profits. In essence, PBR introduces the profit motive into utility regulation.

Fourth, PBR can make the process of introducing new services smoother than COSR would. PBR reduces the need to examine the allocation of utility common costs to a new service because the allocation of common costs to monopoly services is implicitly set by the PBR mechanism. Core customers are protected from being the "deep pocket" for new utility ventures, and conversely, shareholders see reduced regulatory risk from having profits "expropriated" by the regulator.

Fifth, PBR should make the transition to competition easier. The whole idea of PBR is meant to change the mind set of a utility to make it act like a competitive rather than a regulated firm. In fact, PBR is almost always proposed by utilities when there is a perceived threat of growing competition.

However, PBR is not a panacea. Several potential detriments to implementing PBR have been identified. First, much of PBR's benefits derive from lengthening the minimum time between rate cases. In most states the ability to commit for the full term of a PBR plan is fundamentally limited. This is because laws and court rulings require most PUCs to preserve the public interest and to set "just and reasonable" rates. Furthermore, there are no perfect benchmarks for utility services, so the risk of PBR plans falling out of synch with either a utility's accounting costs or market realities is real. In Indiana, IC 8-1-2.5 does enable the IURC to commit to PBR plans. Section 7 of this law does allow for the PBR plan to be "terminated before expiration of the term only if material and irreparable harm to the energy utility, the energy utility's customers, the state, or the safety of the energy utility's workforce has been established."¹⁹

Second, some anecdotal evidence from state experience with PBR in the telecommunication and energy industries indicate that the reduction in administrative costs

¹⁹ Indiana Code 8-1-2.5, Alternative Utility Regulation, section 7.

arising from less frequent rate cases has been offset in part by increased monitoring and evaluation costs. Also, pricing flexibility may require that complaint cases regarding unfair competition be held more frequently.

Third, some argue that by increasing the incentive to cut costs, PBR can cause service quality to deteriorate. Consequently, most PBR plans are supplemented with service quality incentive mechanisms. There is currently not enough evidence to determine if these have been effective. However, some evidence of service quality deterioration has arisen in the telecommunications industry. Recently, the Oregon PUC began a formal action against US West Communications, Inc., alleging noncompliance with service-quality standards.²⁰

Fourth, with the cost-cutting focus of PBR, DSM, environmental, or other social goals may be less likely to be pursued by the utility.

Fifth, PBR can affect utility-customer and customer-customer equity in at least three ways. First, PBR mechanisms can lead to above-market returns that will be perceived by some parties to be unfair. Second, PBR mechanisms often have terms longer than the "normal" time between rate cases. These longer terms can harm parties who are unhappy with their existing rates because there are fewer opportunities to litigate. Also, because of the increased stakes of rate cases under PBR, customers may become the victims of gaming of the initial rates or of the PBR index mechanism. Third, if a PBR plan allows for pricing flexibility, it will likely lead to a reduction in relative rates for customers or customer classes who have alternatives.

D. Performance-Based Ratemaking in Practice

Although experience with performance-based ratemaking is limited in the electric industry, it has become more common in recent years. An overview of thirteen such plans are contained in Table IX.1.²¹ These plans show that the concept is not only a theoretical one, but one that is being put into practice across the nation.

Our discussion in this section largely focused on applying PBR to large portions of a vertically integrated utility. Additionally, we should also recognize that, in a more competitive industry, with unbundled functions, PBR could be applied to those functions that remain under

²⁰ "US West Problems May End Alternative Regulation," Public Utilities Fortnightly, May 15, 1996, p. 17.

²¹ Table IX.1 is excerpted from Comnes, et al., Table 3-1.

regulation, specifically, the transmission and distribution functions. The same arguments made throughout this section are relevant if PBR would be applied to smaller, more narrowly-focused firms.

The challenge is to develop a regulatory structure that aligns the interests of shareholders and customers. Of primary importance is the mechanism through which shareholders and customers share the benefits of improved utility performance. This optimal sharing fraction probably varies widely, depending on the firm's potential for cost reduction, the potential for cost increases beyond the firm's control, the level of uncertainty about the ability of utilities to reduce costs, the regulators objectives, and the price elasticity of demand for electricity.

Table IX.1:
OVERVIEW OF ELECTRIC UTILITY PERFORMANCE BASED REGULATION PLANS

Company	Plan Type	Term of Plan (yrs)*	Scope	Regulatory Status
Central Maine Power (CMP)	Price cap	5	All retail rates	Approved December 1994
NY State Electric & Gas (NYSEG)	Price cap	3	Flow-through allowed for low-income DSM, and excess R&D expenses	Proposed April 1995; Approved September 1995
Niagra Mohawk Power Co. (NMPC)	Price cap	5	All retail rates	Proposed February 1994; Delayed April 1995
PacifiCorp	Price cap	3	Cal only; All prices with no pass-throughs	Approved December 1993
Tuscon Electric Power (TEP)	Price cap (freeze)	5	All retail rates	Proposed June 1995
Consolidated Edison of NY (ConEd)	Revenue per cust. cap	3	Pass-throughs for IPP capacity costs, pensions, DSM program costs, and renewables	Approved April 1995
Pacific Gas & Electric Co. (PG&E)	Base-rate revenue cap, price cap	6	Revenue cap on nonfuel expenses. Price cap for large industrial customers	Proposed in 1994; case before PUC
San Diego Gas & Electric Co.(SDG&E)	Base-rate revenue cap	5	Certain nonfuel expenses	Adopted August 1994
San Diego Gas & Electric Co.(SDG&E)	Modified price cap	2	Some fuel & purchased power costs	Adopted July 1993
Southern California Edison (SCE)	T&D revenue cap	6	All nongeneration revenues	Proposed in August 1994
Southern California Edison (SCE)	Modified price cap	8	All fossil generation revenue requirements	Proposed July 1995
Alabama Power	Sliding scale	Indefinite	All retail rates	Approved in 1982
Mississippi Power	Modified sliding scale	Indefinite	All retail rates	PEP I adopted Dec 1990 PEP II adopted Jan. 1994

*Terms include the litigated base year plus the number of years subject to indexing

X. STRANDED COSTS

The most contentious point of expanding competition in the electric industry is stranded costs.²² Every group involved has an opinion on how these costs should be dealt with, but it is a question that ultimately may be resolved by the courts.

Why has the issue of stranded costs arisen now? After all, utilities have always been faced with the possibility of a resource becoming under used or uneconomic. Customer relocation, changes in customer needs and customer self-generation, as well as poor planning, have left utilities with stranded resources in the past. The costs related to these stranded resources are considered a normal business risk.

Now, however, utilities are faced with the possibility of transformation of the industry's structure due to changing government policies. Some reasonable consideration needs to be given to the recovery of costs related to resource decisions made on good-faith reliance in the continuation of a regulated monopoly marketplace. Utilities made resource decisions and both federal and state commissions approved those decisions based on "used and useful" resources and the obligation to serve.

In the regulated electricity industry, a utility has an obligation to serve all customers in its territory. Because of this obligation, utilities made decisions they may not have made in a competitive market; for example, expanding capacity to meet future electricity demand. These costs are generally included in the rate base. In an era of competition, if a utility loses a customer it loses the chance to recoup the costs incurred to serve that customer when it was required by regulators to do so.

States have a unique stake in the issue of stranded costs. In many states, the utility commission determines if a resource is "used and useful" (one of the determining factors in whether a resource may be included in the rate base). Resources that were previously "used and useful" may become stranded as the industry changes. States also define and review utilities' obligation to serve, and this concept is likely to change with a new industry structure. Finally, because state commissions generally have jurisdiction over retail rates, the recovery of wholesale stranded costs could affect retail costs and thereby, retail rates.

²² Stranded costs are those costs approved for recovery in a regulated environment, but which may no longer be recovered in a competitive market.

In an industry with total equity of \$189 billion,²³ estimates of stranded costs range from \$20-200 billion.²⁴ The majority of stranded costs will be concentrated in a few states--California, Pennsylvania, Texas, New York and Ohio--because they have higher-cost generation such as nuclear power.

In a recent study, Standard & Poor's identified potential winners and losers in the transition to competition, using estimates of lost revenue as a proxy for the effects of stranded costs. In Indiana, S & P estimates annual lost revenue from commercial and industrial (C&I) customers under a reasonable scenario will range from \$77 million, or 8.1% of C&I revenue, for NIPSCO, to a potential annual gain of \$20 million, or 1.9%, for PSI.²⁵

A. What Are Stranded Costs?

Stranded costs are also referred to as stranded (strandable) assets or investments, or transition costs. The name and definition used vary from group to group, which contributes to the difficulty in quantifying the problem. The Federal Energy Regulatory Commission defines stranded costs as any legitimate, prudent and verifiable costs incurred by a utility to provide service to a customer that later leaves the system.²⁶ The costs are further broken down into wholesale and retail stranded costs, depending on what type of customer has departed (or has become a transmission-only customer). The FERC's definition acknowledges that government actions are bringing about competition in the wholesale generating market and creating stranded costs by allowing customers to choose suppliers.

The FERC has identified three main causes of stranded costs: wholesale wheeling, retail wheeling and municipalization. Wholesale wheeling involves the transmission of bulk power from a seller to a buyer--who will then resell the power to retail customers--across a third party's transmission system. Retail wheeling is a direct transfer from a seller to a retail customer over

²³ Energy Information Administration, Financial Statistics of Major U.S. Investor-Owned Electric Utilities, December 1995.

²⁴ Lester Baxter and Eric Hirst, "How Stranded Will Electric Utilities Be?" Public Utilities Fortnightly, February 15, 1995, p.30.

²⁵ John Biardello and Michael Cole, "Direct Access Threatens Electric Utility Revenues," Utilities & Perspectives, November 27, 1995, pp. 6-7.

²⁶ Federal Energy Regulatory Commission, Notice of Proposed Rulemaking, Docket No. RM94-7-000, June 29, 1994, pp. 2-3.

the lines of the local utility. Municipalization is the process by which a retail customer converts its legal status to that of a wholesale customer, thereby qualifying for wholesale wheeling. In Indiana, however, new municipalization is prohibited by state law (IC 8-1-2-95.1 and 8-1.5-2-15).

B. Types of Stranded Costs

The variance in definitions of stranded cost helps account for the variance in estimates of the magnitude of stranded costs, because different items are considered stranded under each definition. There are four categories that are generally agreed upon to be included in the calculation of stranded costs: power plants, long-term power and fuel contracts, regulatory assets and social programs. Within each category, however, there remains disagreement as to exactly what to include.

Power plants, or utility-owned generation, can become stranded if the generating cost is above the market price. In addition to the cost of plant construction, there are other fixed costs associated with generation that can contribute to above-market cost such as taxes, interest payments and operation & maintenance expenses. Disputed items include return on investment, construction work in progress and pollution control and safety equipment.

Long-term purchased power and fuel contracts may no longer be economical as competition develops. A power contract signed at six cents/kWh can become stranded if the market price is four cents. Contracts at market price may even become stranded if competition results in a utility serving less customers than anticipated when the contracts were signed (i.e. the utility requires less power than it contracted for). Fuel contracts become stranded in the same manner as power contracts--the contract price exceeds the market price, rendering the purchase uneconomic. Disagreement in this category focuses on whether contracts were voluntary or required by law under acts such as PURPA.

Regulatory assets are intangibles such as deferred debt cost and accelerated depreciation that appear on a utility's balance sheet. These assets become stranded because while regulators include them in rates, the competitive market does not include them when determining market price. Under competition, recovery of regulatory assets is not backed by future revenue flow as it is under regulation. Debate centers on which assets should be included and what their amounts are, as some items do not appear on the balance sheet.

Social programs such as low-income subsidies, weatherization assistance and environmental protection are provided by utilities as a condition of monopoly service, because utilities are affected with the public interest. Competitive markets typically do not provide such services. While some costs end as soon as a program is discontinued, others, such as environmental compliance, are recovered over several years in rates and can become stranded.

C. Recovery Approaches

Once it can be agreed upon how to estimate stranded costs, the question is who should cover the losses. Should it be the utility and its shareholders, the remaining customers or the departing customers? Several recovery methods have been proposed, differing in their application and responsible party. Table X.1 lists the most often proposed methods, with their pros and cons.

A surcharge on transmission and distribution can place recovery costs on departing customers if they still use the system for transmission access. The biggest drawback to a surcharge is a state/federal jurisdictional dispute that is as of yet unresolved. Depending upon the resolution of this issue, some customers could avoid the charge.

An access charge is similar to a transmission and distribution (T & D) surcharge, but it would be placed on all customers, not just those departing. This charge would more evenly affect all customer classes, but would place part of the burden on customers that did not create any stranded cost. These charges could, however, continue to fund social programs that utilities commonly engage in, such as low-income assistance.

An entrance fee for new market entrants would place part of transition cost on those that will benefit from competition. All sellers of new generation, whether utility, non-utility or self-generators could be covered. Difficulties lie in how to collect the fee, and whether it would be considered anti-competitive to raise the cost of entry.

An exit fee would charge to the departing customer the portion of costs incurred to serve that customer. An exit fee is distinguished from an access charge for transmission or distribution in that the exit fee is not tied to the provision of any service by the utility seeking to recover the costs. As with entrance fees, the disadvantage with exit fees is difficulty in administration and collection, and if state commissions have the authority to instigate a fee.

The T & D surcharge and the exit fee are recovery methods that employ direct assignment of stranded costs to the parties that cause them. Direct assignment is intuitively appealing because the departing customers (wholesale or retail) are assigned a fee based on the costs incurred to serve them. Direct assignment may be easier to define than to apply in a competitive world, however. Some of the questions a direct assignment process has to answer are these: How will the cost assignment be determined? What type of administrative or hearing process will be used? Will costs be assigned using a general formula for all departing customers or by customer-specific analysis? The answers to these questions may vary for different regulatory agencies and utilities.

TABLE X.1: RECOVERY OPTIONS FOR STRANDED COSTS

METHOD	ADVANTAGES	DISADVANTAGES
Surcharge on T & D	Provides for recovery from customers who move to another supplier but still receive service from utility	Potential for state/federal jurisdictional conflicts
Access Charge	Could be imposed on all customers connected to the utility system Could continue to fund social programs	Could not be assessed to customers leaving the system entirely
Entrance Fee	Holds new entrants (generators) that benefit from competition responsible for a portion of transition costs	Possibly viewed as anti-competitive
Exit Fee	Applies to any customer switching suppliers, whether or not they continue to receive transmission service	Potential difficulty in administration and collection of fees State commissions may not have legal authority to impose exit fees

D. Stranded Cost Recovery at the Federal Level

The FERC asserts that utilities should be allowed to recover 100% of their "legitimate, prudent and verifiable" stranded costs, and recovery should come from departing customers that are switching to another supplier (direct assignment of costs). No recovery will be allowed for stranded costs arising from new wholesale contracts unless a recovery plan is specified in the contract. "New" wholesale contracts are defined as those signed after July 11, 1994, the date the proposed rule on stranded cost recovery was published in the Federal Register. Recovery is

allowed for earlier wholesale contracts that were not renewed, provided the seller had a "reasonable expectation" that the contract would be renewed; such recovery may be accomplished through an increase in the customer's transmission and distribution rates. The FERC considers itself the proper forum for the adjudication of stranded costs resulting from municipalization, and state commissions the appropriate body for handling stranded costs resulting from retail wheeling.

The FERC proposes a "lost revenues" approach to calculate stranded costs. With this method, stranded costs are measured as the difference between revenues expected under traditional regulation and under competition. This approach removes the complication of an asset-by-asset review required by a cost-of-service technique. According to the Rule, a customer's stranded cost obligation will equal the difference between the utility's revenue stream estimate and a competitive market value estimate, multiplied by the length of obligation (the reasonable expectation of how long the utility expected to continue to serve the departing customer).²⁷

E. Mitigation

Regardless of how stranded costs may be recovered from customers, without some limited shareholder accountability it will be difficult for regulators to determine if utilities are making reasonable efforts to mitigate stranded costs. In the absence of shareholder liability, utility management may declare some marginally competitive resources stranded and recover the costs from core and departing customers. The most frequently considered method for attaching stranded cost obligation to shareholders is a straight percentage of the stranded cost estimate, ranging anywhere from 0 to 100%.

Another method of creating incentives for utilities to minimize, or mitigate, stranded costs involves the use of performance-based regulation (PBR). PBR has been adopted by many states in regulation of telephone companies, but has not been used as frequently in the electricity sector.

²⁷ FERC Order 888, p. 595.

XI. ECONOMIC DEVELOPMENT

A. Electricity Usage by Indiana Industries

As illustrated by Table XI.1, Indiana's top five industries in terms of gross state production (GSP) consume 63.8% of the industrial electricity sales. Clearly, the price and availability of electricity are important to the individual industries and to the state as a whole.

Table XI.1²⁸ ELECTRICITY SALES BY INDUSTRY

SIC	Name	Current Share of GSP	Current Share of Electricity Sales
20	Food	6.4	5.0
24	Wood	2.7	0.6
25	Furniture	2.2	0.3
26	Pulp and Paper	2.1	2.9
27	Printing	3.9	1.2
28	Chemicals	9.4	19.0
29	Petroleum	0.0	2.7
30	Rubber/Plastics	5.1	4.9
32	Stone & Clay	2.5	4.5
33	Primary Metals	12.2	25.3
34	Fabricated Metals	6.6	4.8
35	Non-Electric Machinery	10.1	5.4
36	Electric Machinery	13.9	4.2
37	Transportation	18.5	9.9
38	Instruments	3.5	0.6
39	Other	1.0	8.6

Since 1987 Indiana's industrial electricity sales growth has been well above the national trend. While sales have increased, the real price for electricity has declined 26.4% for

²⁸ Table 7-1 State Utility Forecasting Group's "Indiana Electricity Projections 1994."

industrial customers.²⁹ Indiana's electric utilities, together with state and local organizations, have worked hard to keep existing industrial energy consumers in the state and to attract new companies. This combined effort is generally termed "economic development".

B. Economic Development

The attraction of new business is one area where electric utilities always engaged in active competition. A business looking to expand its operation may consider sites throughout the state, the nation or possibly, the world. The local utility, often as part of an economic development consortium of government and business organizations, may be a vital element when attracting new business into an area. Special energy rates, financial incentives, location assistance and energy-saving advice are just some of the benefits that electric utilities offer new and expanding companies.

In Indiana I&M, IPL, PSI, NIPSCO, SIGECO, HE, WVPA and IMPA all offer economic development services to potential new customers. Local REMCs and municipal utilities may also engage in economic development activities but their services are usually much more modest in scope and less formalized. The REMCs and municipal utilities may also work through HE, WVPA or IMPA when offering economic development services.

Possibly the most common utility-based economic development program revolves around economic development and/or incentive rates (EDR). Originally, economic development rates specifically identified rates filed with the state commission. They usually contained provisions that related energy rates to the attraction or expansion of customer load. Today economic development rates have a broader meaning and may not always refer to rates that are designated as economic development rates. Time-of-use rates or interruptible rates can also encourage economic development by allowing a new customer to cut energy costs by tailoring production schedules around the utility's peak load times.

A recent survey by Edison Electric Institute found that 55 percent of the utilities responding offered incentive or economic development rates to new or expanding businesses. Often, these inducements help make better use of the utility's existing facilities, which benefits

²⁹ Jaffee, Bruce L., Competition In Energy Markets And Potential Impacts On Economic Development - Draft, May, 1996, p. 10.

all customers in the area, because the additional business helps to pay a portion of the utility's fixed costs.³⁰

In response to an IURC data request I&M reported, in Indiana, 39 customers with a combined load of approximately 63 MVA³¹ currently being served under EDRs. Hoosier Energy reported four customers with a combined load of approximately 5 MW on Economic Development Rates. WVPA has three customers with a total load of about 5 MW on EDRs. PSI currently serves 2 customers with a combined load of approximately 55 MW under economic development tariffs. The customers served under EDRs covered a wide range of businesses including auto manufacturing, steel production, retail stores, hospitals and correctional facilities.

I&M, WVPA and PSI, along with IPL and SIGECO, reported the pursuit of new customers through economic development endeavors. I&M reported 40 prospective customers with a total possible load of 8-10 MVA. SIGECO is pursuing 3 large potential customers with a combined load of about 200 MW. IPL reports 25 prospective economic development customers with a total load of about 53 MW. WVPA is currently pursuing 6 new customers with a potential load of 4 MW and PSI reports 42 potential customers with a total load of approximately 190 MW. It should be noted that some of these utilities are probably pursuing the same customers. The total new business and increased energy sales will be less than the sum of the prospective customers listed previously.

A number of utilities are offering businesses that are expanding or relocating an invaluable tool for reducing long-term costs: energy savings through improved energy efficiency. Particularly in energy-intensive industries, the value of using energy-efficient technologies often pays for itself in just a few years.

³⁰ Tatum, Rita, Utilities Fuel Expansions and Relocations, Area Development Magazine, February, 1996, pp. 77-79.

³¹ The utilities reported their estimated economic development load either in MVA (mega-volt-amperes) or MW (mega-watts). Both are measures of demand. MW is the actual power being used in the circuit while MVA is the power apparently being drawn from the line. The relationship between MW and MVA is called the power factor. With pure resistive electrical loads, such as lighting, the voltage and amperage remain in phase and MW=MVA. When electrical motors, for example as part of an industrial process, become part of the electrical load, inducement on the line will cause the current to lag the voltage then MW will not equal MVA. Source: Industrial Motor Control, Herman, Stephen, L., Alerich, Walter, N., Delmar Publishers Inc., Albany, New York, 1985.

C. How Will Economic Development Programs and Endeavors Change as Retail Competition Becomes Available?

Once retail competition becomes common, attracting new business will focus away from the cost of available energy to other incentives to induce a business to locate in a certain area. Customers will be able to shop the generation market to get low cost energy regardless of their location. As a result, electric utilities will have to become more innovative in the types of products and services they will offer in order to attract new load. Alternatively, local utilities may relinquish their economic development activities to a marketing affiliate.

XII. CONGRESSIONAL ACTIVITY

A. Markey Bill

Representative Edward Markey introduced the Electric Power Competition and Consumer Choice Act of 1996 (H.R. 3782) on July 11, 1996. The Bill is aimed at addressing the risks that utility mergers, utility market power, or utility diversification into new lines of business might harm electricity consumers or undermine the emergence of a fully competitive electricity generation market. The Bill would require each state to initiate a retail competition rulemaking proceeding (no deadline is specified) pursuant to certain federal standards.

B. Schaefer Bill

On July 11, 1996, Representative Dan Schaefer introduced the Electric Consumers' Power to Choose Act of 1996 (H.R. 3790). The language in the Schaefer Bill clearly requires all utility retail customers to be able to purchase retail electric energy services from any person offering to provide those services to such customers by no later than December 15, 2000. The tight deadline would require that all retail customers be provided access to alternative suppliers at virtually the same time.

The Schaefer Bill requires that states which elect to establish retail choice develop rules that do certain things, but the specifics of the rules appear to be left to the states. The Bill provides that states create rules that provide for the following:

- Retail Customers - Choice of electric suppliers by December 15, 2000
- States - Six months to elect retail choice
- FERC - Will act if states take no action
- Nonregulated Utilities - Six months to elect retail choice
- PURPA - Repealed once choice is allowed (contracts in effect July 11, 1996, will stand)
- PUHCA - Repealed once choice is allowed
- Renewables - Promoted with system of tradable credits
- Rates - States set flexible pricing and incentive-based rates
- Stranded Cost - States decide if recovery is appropriate
- Transmission/Distribution - Facilities assigned federal or state jurisdiction by seven-part FERC test

To date neither of these pieces of legislation have passed out of full committee. But versions of the Schaefer and Markey Bills are expected to be reintroduced in the next Congress. Representative Bliley, Chairman of the House Commerce Committee, said on September 4, 1996, that restructuring the electric utility industry will be a singular priority of the 105th Congress and that he will try to accomplish in the electric utility markets what he helped spearhead in telecommunications.

XIII. LIST OF ACRONYMS

AC - Alternating current
AEP - American Electric Power
ALJ - Administrative Law Judge
Btu - British Thermal Unit
CAAA - Clean Air Act Amendments of 1990
C & I - Commercial and Industrial
COSR - Cost-of-Service Ratemaking
CPUC - California Public Utility Commission
DC - Direct current
DSM - Demand-Side Management
EDR - Economic Development Rate
EPA - Energy Policy Act of 1992
FERC - Federal Energy Regulatory Commission
FPA - Federal Power Act 1935
FPC - Federal Power Commission
GSP - Gross State Product
G&T - Generation and Transmission
HE - Hoosier Energy Rural Electric Cooperative, Inc.
IAC - Indiana Administrative Code
IC - Indiana Code
I&M - Indiana Michigan Power Company, subsidiary of AEP
IMPA - Indiana Municipal Power Agency
IPL - Indianapolis Power and Light
IOU - Investor-Owned Utility
IRP - Integrated Resource Plan
ISO - Independent System Operator
IURC - Indiana Utility Regulatory Commission
kV - kilovolt
kWh - kilowatt hour
MegaNOPR - Notice of Proposed Rulemaking Regarding Promoting Wholesale
Competition Through Open Access Non-Discriminatory Transmission
Services by Public Utilities
MMBtu - million Btu
MVA - Mega-volt-amperes
MW - Megawatt

NERC - North American Electric Reliability Council
NHPUC - New Hampshire Public Utility Commission
NI - NIPSCO Industries, Inc.
NIPSCO - Northern Indiana Public Service Company
NOPR - Notice of Proposed Rulemaking
NO_x - Nitrogen Oxide
NUG - Non-Utility Generator
OASIS - Open Access Same-Time Information System
PBR - Performance-Based Regulation
PCR - Price Cap Regulation
PSI - PSI Energy
Poolco - An alternative power pooling institution
PUC - Public Utility Commission
PUCO - Public Utility Commission of Ohio
PUHCA - Public Utility Holding Company Act 1935
PURPA - Public Utility Regulatory Policies Act 1978
REA - Rural Electrification Administration
REMC - Rural Electric Membership Cooperative
RIN - Real-Time Information Network
ROE - Return on Equity
RUS - Rural Utilities Service
S&P - Standard & Poor's Utilities Rating Service
SIC - Standard Industrial Code
SEC - Securities and Exchange Commission
SIGECO - Southern Indiana Gas & Electric Company
SO₂ - Sulfur Dioxide
T & D - Transmission and Distribution
WVPA - Wabash Valley Power Association, Inc.

XIV. GLOSSARY³²

Adequacy: Ensuring the sufficient availability of supplies in order to preserve reliability. It includes unit commitment, economic dispatch to follow load, and coordinated maintenance scheduling of individual components and planning new generation and transmission capacity.

Ancillary Services: Necessary services that must be provided in the generation and delivery of electricity. As identified by the FERC, they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and the economic dispatch of plants); contractual arrangements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).

Avoided Cost: The basis for the price an electric utility should pay a qualifying facility for the purchase of power. Under PURPA, it is the lowest cost that the utility would otherwise incur to generate the power itself or purchase it from elsewhere if it did not make the purchase from the QF. It is analogous to marginal cost.

Bilateral Model: A retail competition model that has the market organized by contracts between two parties, rather than a centralized exchange such as a power pool (see poolco).

Bulk Power Market: The market in which large amounts of electricity at high voltages is exchanged, usually from one utility to another for the purpose of resale.

Business Risk: Inherent in the operation of any business, it includes external factors such as the state of the economy, competition, product substitutes, technological obsolescence and the cost and availability of labor and raw materials.

Certificate of Need Law: This law, codified as IC 8-1-8.5, requires a utility to demonstrate to the IURC the need for a new generating unit before construction begins.

Combustion Turbine: A generating unit built to meet peak load, this is a rotary engine usually powered by natural gas.

³² A major source for this glossary is P.U.R. Glossary for Utility Management, 1992, compiled by the editors of Public Utilities Reports, Inc., Arlington, VA.

Common Costs: Those costs incurred by a utility in providing more than one service, but which cannot be assigned solely to one or another function, as they relate to the utility's overall operations.

Contract Imbalance Quantity: The cumulative difference between the quantities of a commodity received and quantities actually delivered under contract from inception through the most current billing period.

Control Area: A geographic region in which a utility is responsible for operating the power (transmission and distribution) system.

Cooperative: A business entity similar to a corporation, except that ownership is vested in members rather than stockholders, and benefits are in the form of products or services rather than profits.

Core Customers: The customers in a utility's traditional service territory. Also called native load customers.

Corporate Unbundling: The process by which a vertically integrated firm would sell off various parts of its business to other parties. For example, an electric utility could sell off its generation, transmission, or distribution businesses.

Cost of Service Ratemaking: Setting a utility's rates based on the amount of money to fund its operations, including expense liabilities of all kinds, depreciation, and a fair rate of return.

Cross-Subsidization: The use of resources or revenues from one part of a company's operations to fund operations in another (sometimes weaker) part of the company.

Debt Leverage: Or debt ratio, this is the proportion of borrowed capital (bonds) as compared with equity (stock), or as compared with total capital.

Demand-Side Management (DSM): Conservation resource planning considering factors affecting energy usage for each customer class, and generally designed to reduce or shift load.

Direct Assignment: A type of recovery option for stranded costs, a fee assigned to departing customers based on the costs to serve them.

Distribution: The component of the electric system that delivers electricity from a substation where the electricity from the transmission system is reduced to a voltage appropriate for use by customers. Also a functional classification relating to that portion of utility plant used for the purpose of delivering electric energy from convenient points on the transmission system to the consumers. Also can be called the distribution system.

Economic Dispatch: The process by which a generating system consisting of multiple generating facilities is operated to maximize the efficiency of the system and minimize its operating costs. It involves using the system's most efficient (having the lowest operating costs) generating unit that is not already fully utilized when additional capacity is needed and backing down or taking off the least efficient (highest operating cost) operating unit when the need for capacity is decreased. Sometimes called central dispatch.

Economic Development: Organized efforts to attract new business into an area or to encourage existing business to expand.

Economic Development Rates (EDR): Discounted rates offered to industrial customers as an incentive to locate or expand within a utility's service area and thus stimulate economic growth within that area.

Elasticity of Demand: The degree to which demand will vary with a change in price.

Embedded Costs: A cost which can no longer be avoided or minimized by the curtailment or reduction of output, because it has been incurred in some historical period of time, and cannot be varied.

Energy Policy Act of 1992 (EPAct): A comprehensive federal act generally designed to improve the efficiency of energy use in the United States. This act established a class of generators known as exempt wholesale generators that are exempt from PUHCA and PURPA restrictions.

Entrance Fee: A type of recovery option for stranded costs, this would hold new entrants (generators) that benefit from competition responsible for a portion of transition (stranded) costs.

Equity: The part of a utility owned by stockholders, represented in the financial statement of a utility as the value of outstanding common and preferred stock, retained earnings, and any additional paid-in capital.

Evergreen Contract: A contract between parties that automatically renews unless one party provides notice that it will terminate the contract after a specified time or event.

Exit Fee: A type of recovery option for stranded costs, this would apply to any customer switching suppliers, whether or not they continue to receive transmission service.

Financial Risk: This is the risk arising from the method the firm uses to finance its investments and it is reflected in the firm's capital structure. It is the risk that less income will be available to the common shareholders due to the use of fixed cost financing (debt and preferred stock).

Flue Gas Desulfurization Unit: See scrubber.

Functional Unbundling: A process by which a vertically integrated firm would split itself up into separate functions. For example, an electric utility could organize into a generating group, a transmission group, and a distribution group. The utility would retain corporate ownership of all three business groups.

Generation: The process of generating electricity. Also, the component of a utility's electric system that produces the electricity to be transmitted and distributed to customers.

Greenfield Site: A section of land that has been set aside for industrial or commercial development, previously undeveloped. A site that was previously developed and has been set aside for renewed development or restoration is called a "brownfield site."

Holding Company: An organization not directly engaged in the operation of any business, but which owns the stock of other companies.

Incentive Regulation: See performance-based regulation.

Incremental Cost: The additional costs incurred from the production or delivery of an additional unit of utility service, usually the minimum capacity or production that can be added.

The additional cost divided by the additional capacity or output is defined as the incremental cost.

Independent Power Producer (IPP): An entity, other than a public utility, that offers electric power for sale to the public, usually on a wholesale basis. The term is sometimes meant to include qualifying cogeneration or small power facilities under the Public Utility Regulatory Policies Act that produce power for sale at wholesale to an electric utility.

Independent System Operator: No exact definition yet exists, but generally it is an independent entity or institution that would control the regional transmission grid; that is, the transmission assets and whatever generation is needed for reliability.

Integrated Resource Planning (IRP): A strategy used by utilities and regulators to arrive at the least-cost mix of resources available to provide reliable service.

Interruptible Rates: Discounted rates that are offered to customers in exchange for the possibility of service interruptions by the utility, either at its discretion or otherwise prescribed by contract, generally in periods of high demand or short supply or during system emergencies.

Investor-Owned Utility (IOU): A utility company owned and operated by private investors as opposed to governmental or cooperative-type ownership.

Load Curtailment: A temporary reduction in the amount of energy receivable by a customer due to shortfalls in supply.

Load Factor: A measure of the degree to which physical facilities, such as a power plant or gas pipeline system, are being utilized. The ratio of average output or consumption to peak output or consumption.

Load Following: The process by which a utility meets the variations in electricity demand by preparing generating units for operation under unit commitment schedules, which reflect forecasted load changes over daily, weekly, and seasonal cycles plus an allowance for random variations.

Loop Flow: A physical characteristic of a transmission system that every flow of power from a power plant to a distribution system affects the entire transmission system (or network), not just the most direct path.

Lost Revenues Approach: A method proposed by FERC to calculate stranded costs. Stranded costs are measured as the difference between revenues expected under traditional regulation and under competition.

Marginal Cost: The cost to a firm to produce the last unit of a good or service.

Market Power: The extent to which a single firm can influence the market price.

MegaNOPR: Common name for the FERC NOPR (Notice of Proposed Rulemaking) that resulted in Order 888; among other things, it provides nondiscriminatory open access to the transmission system for all market participants.

Midwest ISO: An ISO attempting to be formed by over twenty utilities in the midwest.

Municipal Utility: A utility that is owned and operated by a municipal government. These utilities are organized as nonprofit local government agencies and pay no taxes or dividends. They raise capital through the issuance of tax-free bonds.

Municipalization: The process by which a retail customer converts its legal status to that of a wholesale customer, thereby qualifying for wholesale wheeling.

Natural Monopoly: An activity such as the provision of natural gas, water, and electrical service characterized by economies of scale wherein the cost of service is minimized if a single enterprise is the only seller in the market.

New Wholesale Contracts: Refers to contracts that will not be eligible for wholesale stranded costs at the FERC. They are defined as those contracts signed after July 11, 1994, the date the proposed rule on stranded cost recovery was published in the Federal Register.

Non-Utility Generation: Generation by producers having generating plants for the purpose of supplying electric power required in the conduct of their industrial and commercial operations.

North American Electric Reliability Council (NERC): A nonprofit organization formed for the purpose of coordinating electric system operation and planning throughout North America. NERC was formed in 1968 in reaction to the Northeast blackout of 1965, and is organized through nine regional councils consisting of individual member electric utilities in the United States, Canada, and Mexico.

Obligation to Serve: One of the duties of a public utility, usually referring to mandates to serve all prospective customers, to provide adequate service, and to render safe, efficient, and nondiscriminatory service.

Order 888: The FERC's final rule on nondiscriminatory open access transmission, issued in April 1996.

Order 889: A FERC rule establishing an open access same-time information system (OASIS) for the provision of transmission information, issued in April 1996.

Pancaked Transmission Rates: Said to occur when a seller attempts to wheel electricity over several control areas, and must pay a separate transmission charge for using each system.

Performance-Based Regulation: An alternative to traditional cost-of-service regulation which usually includes a formula for the sharing of earnings in excess of a benchmark rate between shareholders and ratepayers. Often coupled with some form of pricing flexibility for competitive services as well as an agreement to maintain stable rates for basic services for a specified period of time.

Poolco: A retail competition model with the main feature that power is exchanged through a power pool via a bidding process; as opposed to the bilateral model.

Power Marketers: Brokers who facilitate deals between buyers and sellers of power. They do not own generation or transmission assets.

Power Pool: Two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs. Essentially a regional organization of interconnected electric utilities designed to improve coordination, planning, and operation of generation and transmission facilities so as to maximize economy and reliability of service in supplying mutual energy loads.

Benefits can include improved reliability of power supply, diversity of resource mix, shared spinning reserve, joint ownership of new power plants, power exchange agreements, and economy energy sales.

Price Cap Regulation: Alternative regulation plan that employs a maximum permitted rate for flexibly priced services.

Qualifying Facility (QF): As defined in the Public Utility Regulatory Policies Act of 1978, a small power producer or cogenerator that can sell its electricity to public utilities. QF electricity can be generated from hydro power, wind, solar, geothermal, cogeneration, biomass, or waste product combustion.

Rate Base: The accumulated capital cost of facilities purchased or installed to serve a public utility's customers, upon which the utility is allowed to earn a return. Major components include tangible and intangible plant, and working capital. Generally, rate base represents the property used and useful in public service, whose investment value is determined by a regulatory commission based on fair value, prudent investment, reproduction cost, or original cost, subject to adjustment.

Rate of Return Bandwidth Regulation: Alternative regulation plan that adjusts rates based on the earned rate of return of a utility. Also called sliding scale, or revenue sharing.

Reactive Power: Utilized to control voltage on the transmission network, particularly, the portion of the electrical power flow incapable of performing real work or energy transfer. Reactive power is that portion of electricity that establishes and sustains the electric and magnetic fields of alternating current equipment. It must be supplied to most types of magnetic equipment, such as motors or transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment, such as capacitors, and directly influences electric system voltage. It is measured in megavars.

Regulatory Assets: Intangibles such as deferred debt cost and accelerated depreciation that appear on a utility's balance sheet.

Reliability: The ability to deliver uninterrupted electricity to customers on demand, and to withstand sudden disturbances such as short circuits or loss of system components,

encompassing both the reliability of the generation system and the transmission and distribution system. It may be evaluated by the frequency, duration, and magnitude of any adverse effects on consumer service. The guarantee of system performance at all times and under all reasonable conditions to ensure constancy, quality, adequacy, and economy of electricity.

Reserve Margin: The difference between the dependable capacity of an electric utility's system and the anticipated peak load for a specified period. Reserve capacity is needed in case of failure of a generating unit in operation or of supplies to the system, interruption of transmission service, or customer demand in excess of generation plant capability. Reserve may be obtained from spare generating units or through interconnection.

Retail: Sales covering electrical energy supplied to residential, commercial and industrial end-use purposes.

Retail Wheeling: The direct transfer of electricity from a seller to a retail customer.

Return on Equity (ROE): A measurement of the return received by common stockholders on their investment in a firm, it is the ratio of net income or earnings (after deduction of expenses) to the book value of common and preferred stock plus retained earnings. A utility is allowed (but not guaranteed) to earn the ROE authorized by a regulatory commission in a general rate case. Actual ROE is a measure of the profitability of the investment by common stockholders, and can reveal the effectiveness of management and financial decisions. Also called return on common equity.

Revenue Cap: An alternative regulation plan that caps a utility's allowed revenues with an external index. Subject to the cap, a utility is permitted to maximize profits.

Scrubber: Equipment designed to reduce sulfur emissions from coal-fired power plants; devices that use a liquid spray to remove aerosol and gaseous pollutants from an air stream. Also known as a flue gas desulfurization unit.

Senate Enrolled Act 637: Codified as IC 8-1-2.5, this statute enables the IURC to consider alternative ratemaking plans, among other things.

Service Quality: The level of performance that a utility must maintain in rendering adequate service.

Social Programs: Because utilities are affected with the public interest, these are programs provided by utilities as a condition of monopoly service. They include low-income subsidies, weatherization assistance and environmental protection.

Spinning Reserves: Reserve electric generating capacity that is connected to the transmission system and ready to furnish load.

Stranded Costs: Costs that electric utilities are currently permitted to recover through their rates but whose recovery may be impeded or prevented by the advent of competition in the industry.

Tariff: A published collection of rate schedules and terms and conditions for use of utility service.

Time-of-Use (TOU) Rates: Utility rates that vary depending upon the time in which services are consumed.

Transmission: That portion of a utility plant used for the purpose of transmitting electricity in bulk to other principal parts of the system or to other utility systems, or to expenses relating to the operation and maintenance of the transmission plant.

Transmission System: An interconnected group of high voltage electric lines.

Used and Useful: In service and therefore eligible for inclusion in rate base.

Wheeling: An electric utility operation wherein transmission facilities of one system are used to transmit power produced by another system.

Wholesale: The sale of a good in large quantities for resale.

Wholesale Market: See bulk power market.

Wholesale Wheeling: The transmission of bulk power from a wholesale seller to a wholesale buyer who then resells the power to retail customers.

Z Factor: A rate adjustment to reflect exogenous changes — i.e., influences upon cost which are outside the control of a utility, such as tax law changes, stranded costs, regulatory assets, etc.